AN ENGINEERING STUDY OF THE DRIFTWOOD-BENEZETTE GAS FIELD IN PENNSYLVANIA

Clem Brandon Connally

An Engineering Study of the

Driftwood - Benezette Gas Fields In Elk, Cameron, and Clearfield Counties of Penna.

By Commander C. B. Connally* and P. F. Fulton**

I. Introduction

This paper presents a petroleum engineering approach to the evaluation of production practices employed in the Driftwood-Benezette gas field in Pennsylvania, and compares the results of such practices with those which might have been accomplished had the field been developed and operated in the most efficient manner, or in accordance with modern petroleum conservation laws.

The Driftwood-Benezette gas field is important to this study only in that it provides a means for illustrating production practices generally employed in all Pennsylvania gas fields. Therefore, no attempt has been made to set forth details of engineering and geologic interest not closely related to production practices.

Petroleum production practices in Pennsylvania have remained the same in principle since the discovery of the Drake well in 1859. There are no laws restricting petroleum production even though it is a well known fact that "wide-open" flow may cause great underground losses of oil or gas; moreover, there are no laws protecting landowners' correlative rights—the right to enjoy the use of one's property so long as this enjoyment does not do injury to others.[1]

There have been several proposals[2] for petroleum conservation laws which would require or encourage the development and operation of a petroleum reservoir as a single unit rather than on the wasteful and costly basis of "every man for himself." None has been enacted, however, and it appears that Pennsylvania may become the leading oil and gas producing state where no such laws are in effect. It is indeed a mystery why no such laws have been enacted. One would think that Pennsylvania, the founding state of the petroleum industry, would have been a leader in petroleum regulatory law. There must be some merit to petroleum conservation and unitization laws, for no state has ever repealed such a law. The Interstate Oil Compact Commission, which through engineering, research, and other committees functions to advise the various states on petroleum regulatory measures, has recommended the enactment of a unitization law.[3]

Does it not seem logical that there should be a minimum waste of petroleum resources, and that a landowner should be permitted to recover his fair share of the oil or gas underlying his land, and only his fair share, without the drilling of unnecessary wells?

Perhaps many Pennsylvanians are not acutely aware of the waste of their petroleum resources or the infringement on their correlative rights caused by maximum-rate production practices employed in Pennsylvania. This study has been made in an attempt to illustrate, quantitatively, the effects of such practices as they relate to natural-gas production.

The Driftwood-Benezette field provides a good example for illustrating natural-gas production practices in Pennsylvania. This field was intensely drilled soon after its discovery and allowed to produce at maximum rate. Each landowner had to get his gas to the surface before his neighbor drained it away. It is the authors' opinion that this caused the drilling of about 200 more wells than would have been necessary to produce the field efficiently, and that open-flow production will cause the underground loss of at least 20 billion cubic feet of gas, with a net value of approximately $2,000,000.

Unfortunately, accurate results cannot be obtained from the data available. Throughout this study, however, the authors continually strove to favor the use of results and assumptions which would not exaggerate the adverse effects of existing production practices.

II. Inadequacy of Engineering Data

It became apparent at the beginning of this study that the lack of petroleum regulatory laws has resulted in an inadequacy of engineering data.

It is impossible for engineers to make accurate engineering studies, upon which plans for future gas production, transportation, storage and marketing must be based, without complete and accurate engineering information. Furthermore, this information must be readily available, at a central source, to all interested parties.

In 1935 the Bureau of Mines introduced a method for computing gas-well capacities and for applying this information to production practices.[4] The basic equation[5] set forth in that report is used throughout the natural gas producing industry—even in Pennsylvania—yet the data available on Pennsylvania wells for use in that equation are entirely inadequate for accurate calculations.

Though there are no laws preventing operators from obtaining these data on their own wells, few will voluntarily close in a well or restrict its production while their neighbor drains gas from under their land at a maximum rate. Further, in order to provide maximum benefit, this information must be standardized and compiled under a well organized program, enforced by a central authority and maintained readily available at a central source.

This lack of adequate information has obviously lead to inaccuracies in much of the data that have been obtained. Probably the greatest inaccuracies have been in measuring the shut-in pressures of the wells, the very heart of the information used in petroleum engineering studies.

Another source of difficulty to an engineer is the confidential nature of production information on privately owned wells. An accurate evaluation of a well's performance requires the comparison of that well with other wells in the near vicinity, and an evaluation of the reservoir as a whole may require the use of performance data on any well in the reservoir.

Specific examples of either inadequate or inaccurate information encountered during the course of this study are listed as follows:

1. Shut-in well pressures are often inaccurate. Most wells were shut in for less than 24 hours when their pressures were recorded, some for only an hour or less.

2. The entire reservoir has never been shut in and the average pressure recorded, nor are individual wells shut in periodically for this purpose. One accurate reservoir pressure, after sufficient gas had been produced to show a pressure decline, would have been sufficient to compute total gas reserves. As the situation stands, operators are merely guessing at gas reserves, and no one will ever know how much gas is lost due to production practices.

3. Production information on privately owned land is confidential and, there-

*Commander, ~~C. E. C.~~, U. S. Navy.

**Associate Professor, University of Pittsburgh, Petroleum Engineering Department.

best advantage its resources of men and materials.

Acknowledgement

In preparing this article, the author gratefully acknowledges the generous advice and contributed suggestions of D. B. Taliaferro, J. W. Watkins, and H. N. Dunning, all members of the staff at the Bartlesville Station, K. F. Anderson at the Dallas office, and R. P. Dobyns at the Wichita Falls office.

REFERENCES

[1]Chief, Division of Petroleum Technology, Bureau of Mines, U. S. Department of the Interior, Region IV, Bartlesville, Okla.

[2]Hamontre, H. C., and Ball, Cleo G., "Improved Bulk-Volume Cell Speeds Porosity Determinations," Oil and Gas Jour., Vol. 51, January 19, 1953, pp. 94-96.

[3]Dunning, H. N.; Johansen, R. T.; Walker, C. J.; Powell, J. P., and Watkins, J. W., "Field Test of a Detergent in Oil Recovery," Oil and Gas Jour., Vol. 54, No. 19, p. 115, September 12, 1955.

[4]Watkins, J. Wade; Willett, F. R., Jr., and Arthur, Charles E., "Conditioning Water for Secondary Recovery in Midcontinent Oil Fields," Bureau of Mines Rept. of Investigations 4930, 1952, 86 pp.

[5]Rall, Cleo G., and Wright, J., "Analysess of Formation Brines in Kansas," Bureau of Mines Rept. of Investigations 4974, 1953, 40 pp.

[6]Ayers, Marion L.; Dobyns, Rollie P., and Bussell, Robert Q., "Resistivity of Water from Subsurface Formations," printed by North Texas Oil and Gas Association as a cooperative report with the Bureau of Mines, 1952.

[7]Armstrong, F. A.; Heemstra, R. J., and Kincheloe, G. W., "Amperometric Instrument for Quantitative Determination of Oxygen Dissolved in Oil-Field Brines," Anal. Chem., Vol. 27, August, 1955, p. 1296.

[8]Watkins, J. Wade, and Wright, Jack, "Corrosive Action on Steel By Gases Dissolved in Water," The Petroleum Engineer, Vol. 25, No. 12, November, 1953, p. B-50.

[9]Dunning, H. N.; Hsiao, Lun, and Johansen, R. T., "Displacement of Petroleum from Sand By Detergent Solutions," Bureau of Mines Bept. of Investigations 5020, 1953, 19 pp.

[10]Dunning, H. N.; Moore, J. W., and Myers, A. T., "Properties of Porphyrins in Petroleum," Ind. Eng. Chem., Vol. 46, 1954, p. 2000.

[11]Joers, J., and Smith, R. V., "Determination of Effective Formation Permeabilities and Operation Efficiencies of Water Input Wells," Producers Monthly. Vol. 18, No. 12, October, 1954, pp. 21-28; also Petroleum Engineer, Vol. 26, No. 11, October, 1954, pp. B-82 and following.

[12]Watkins, J. Wade, and Mardock, E. S., "Use of Radioactive Iodine As a Tracer in Water-Flooding Operations," Jour. Petrol. Technol., Vol. 6, No. 9, September, 1954, p. 117.

[13]Meadows, Paul, and Hawkins, Murphy E., "Secondary-Becovery Potentialities of the Buckrange Reservoir, Stephens Oil Fields, Columbia, Nevada, and Ouachita Counties, Ark.," Bureau of Mines Rept. of Investigations. In press.

Wrather Retires As Director Of U. S. Geological Survey

Dr. William Embry Wrather, who recently retired as Director of the Geological Survey "has guided Survey Activities through 12 years of growth in service to the Nation during the difficult years of war and the later period of adjustment to an expanding economy," according to Secretary of the Interior Douglas McKay. Dr. Wrather was appointed in 1943, at a time when heavy demands were being made on the Survey for emergency services to the Nation in the midst of a world war.

Born in Kentucky and a graduate of the University of Chicago in geology and law, Dr. Wrather brought to the Survey a unique combination of administrative abilities gained through years of experience in the petroleum industry.

In 1954 he was given the 50th John Fritz Medal, and cited as "a geologist of worldwide experience and fame; an outstanding scientist and historian; a wise leader distinguished for his service to the Nation."

Under Dr. Wrather's leadership much progress was made in various facets of the science of hydrology and in the accumulation of basic water facts.

A rapidly expanding program of water resources investigations has been guided toward broad objectives in appraising the Nation's water resources, developing a better understanding of the principles governing the occurrence and movements of water, and in determining current water use and water requirements.

Important advances have been made in the techniques of appraising the water supplies of the Nation. Improvements in quantitative methods of solving complex ground-water problems, and of analyzing artesian acquifers have resulted from continued research.

Three hundred gallons of jet fuel are required to taxi a current jet bomber from the warm-up ramp to the end of a runway for take-off, usually a distance of about one and one-half miles.

More than 700 varieties and grades of oil-based synthetic rubber have been produced.

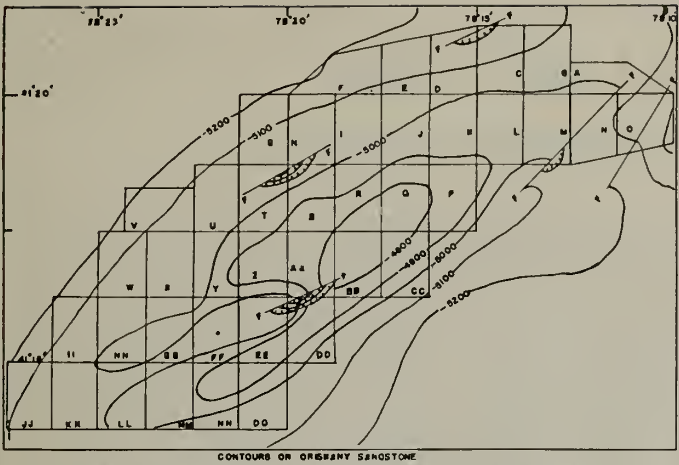


Figure 1—Structure Map, Driftwood-Benezette Gas Field

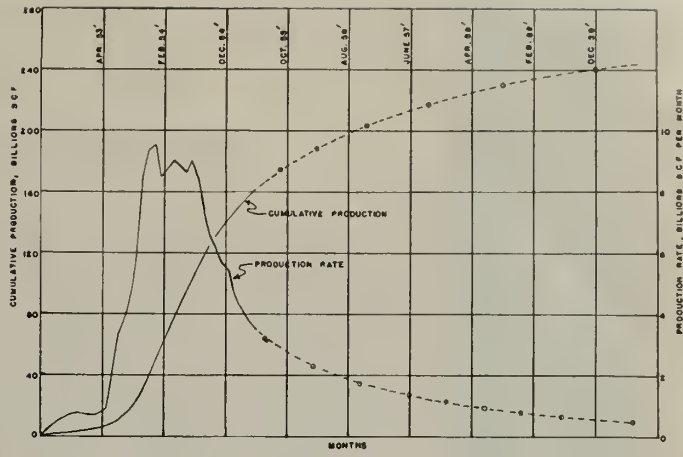


Figure 3—Cumulative Production and Production Rate vs. Time

fore, not available to the public or to all interested producing companies.

4. No records could be found showing shut-in pressures for wells on more than one occasion after having been cut in to the pipeline. This information is necessary in order to determine a well's performance characteristics and behavior as described in Section V, A and B.

5. No one producer or regulatory body has all the data on all the wells in the reservoir. Absence of monthly production rates for all wells is the most important example of this inadequacy. Other missing information might be as follows: The drilling method used, whether or not a well was shot, original well-head pressures and shut-in time, and whether or not a well had been abandoned.

6. The reservoir temperature has never been measured.

7. Very few reservoir sand thicknesses have been recorded.

8. Well locations are not recorded in a standard form.

9. Neither the porosity nor the permeability of the sand has ever been measured.

In view of the above, the results brought out in this study are not nearly so accurate nor significant as they otherwise might have been. Perhaps the inadequacy of this study will serve to indicate the necessity for such state statutes as will provide for the compilation of information necessary to conduct accurate engineering studies.

III. History of Operations
A. The Reservoir

The Driftwood-Benezette gas field is the largest known gas field in Pennsylvania, covering about 42,000 acres in Elk, Cameron, and Clearfield Counties. Production is from the highly faulted Oriskany sandstone, which in this area is mostly "medium-grained, light gray, quartzose, slightly calcareous."[6] The Oriskany is capped by the Onondaga limestone formation.

Figure 1 shows the approximate area of the reservoir superimposed on a contour map on the Oriskany sandstone as constructed by Fettke.[7] Figure 2 shows locations of all wells numbered in the sequence in which they were completed or drilling operations abandoned, although numbers for dry holes have been omitted on the drawing.

It should not be construed that the reservoir has such a jagged boundary as is indicated by the block areas in Figures 1 and 2. These blocks established by the authors were used to compute the average reservoir pressure as described in Section IV.

This field is located on the Driftwood anticline, the highest point on which is the Driftwood dome, located about one mile northeast of the town of Driftwood. This dome is not shown in Figure 1

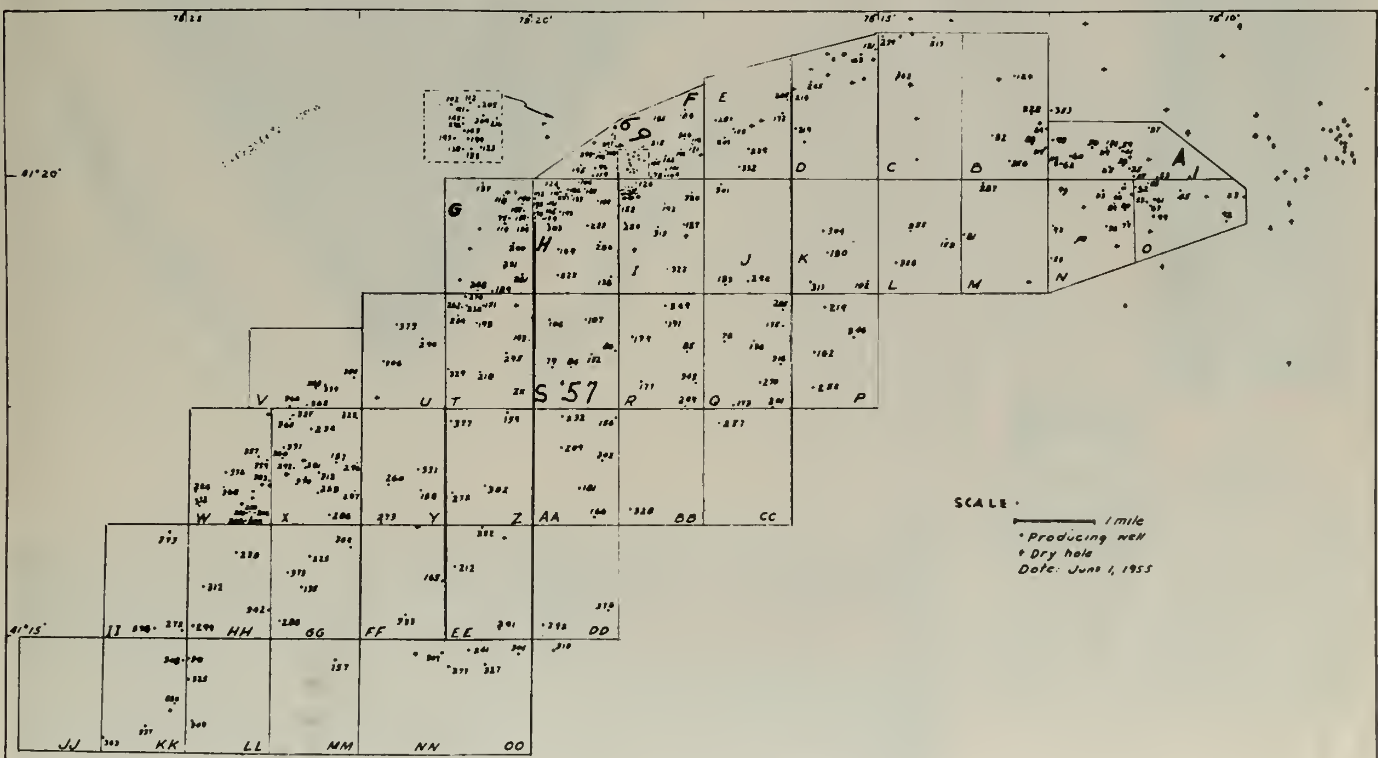
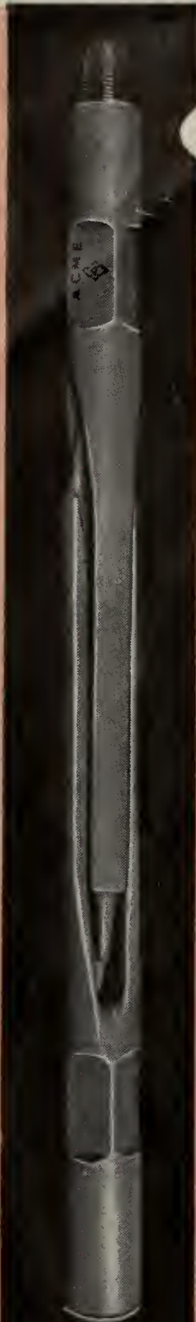


Figure 2—Block area map, Driftwood-Benezette Gas Field



"are YOU getting ENOUGH FOOTAGE?"

1. To MAKE MORE MONEY you have to get a higher price for your drilling, or get more drilling from your machine and tools. The progressive drilling contractor is always after both—more money and more footage.

2. To get you MORE FOOTAGE, Acme spent more than a decade developing a superior alloy jar. How? By the same quality methods that have made the Acme Carbon Jar victorious over all competition. Today over 85% of the carbon jars made in America are Acme and they wear as long as a competing weldless jar in many sizes.

3. To get LONGER WEAR — much longer wear — in all formations, the Acme alloy jar has been perfected. Look up the word Acme in your dictionary; it comes from the Greek word, Akme, meaning perfection, peak of progress. Here is how we live up to our great name.

4. We have installed the MOST MODERN EQUIPMENT to manufacture jars. Exclusive with Acme are the latest technological improvements in the physical treatment and welding of jar steel. No one else offers you the benefit of such superior manufacturing facilities. Acme Alloy Jars — like Acme Carbon Jars — are superior because they are made by superior methods and machinery.

5. We use SUPERIOR STEEL in Acme Alloy Jars. It is a triple strength alloy steel, grade AISI 4340 made out of chromium, molybdenum, and nickel. It is a longer wearing alloy steel than the single alloy used in a competing make. Acme Alloy Jars have 1300% more alloy in them than any other make on the market. We use a chrome-moly-nickel steel which is rich in nickel, producing a greater depth of hardness penetration than the single alloy used by a competing make. LONGER WEAR is the bonus you get from the superior alloy steel in Acme Alloy Jars.

6. We use ATOMIC AGE WELDING methods. The welding techniques of today permit use of alloy steels far superior to those used at the time weldless jars were first made. The atomic age has made the weldless method obsolete. We put one electric weld in a set of Acme Alloy Jars. It is stronger than steel. The weld is X-rayed by an electro-magnetic process so that no bad welds can get past inspection. This one weld is in the crotch where the steel is 50% heavier than in the rein section. Both sections of the jars are drop forged. This method of making alloy jars enables Acme to use a superior alloy steel, and you get a superior alloy jar with less breakage and longer wear.

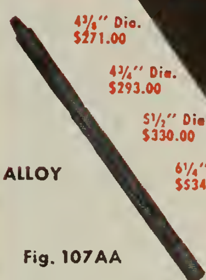
7. Acme, like its parent company, Stardrill-Keystone, has a basic policy of QUALITY FIRST. While another manufacturer of alloy jars uses an alloy steel containing only ⅕ of 1% alloy content, Acme, in its alloy jars, uses a steel containing 3% of alloy — or 1300% more.

8. Acme gives you MORE STEEL. For example our 5½" Acme Alloy Jars weigh 425 lbs. . . . 10% more than a competing make. At the same price.

SINCE 1900 IN OUR 56TH YEAR

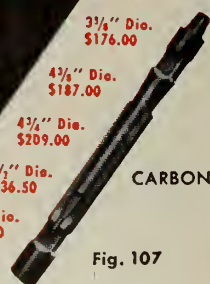
VICTORIOUS JARS

ACME ALLOY JARS
made of
MOLYBDENUM
CHROMIUM
NICKEL
Alloy Steel



ALLOY
Fig. 107AA

Alloy	
3¼" Dia.	$244.00
3⅛" Dia.	$244.00
4⅜" Dia.	$271.00
4¾" Dia.	$293.00
5½" Dia.	$330.00
6¼" Dia.	$534.00
6½" Dia.	$560.00
7" Dia.	$690.00



CARBON
Fig. 107

Carbon	
2⅛" Dia.	$154.00
3¼" Dia.	$165.00
3⅝" Dia.	$176.00
4⅜" Dia.	$187.00
4¾" Dia.	$209.00
5½" Dia.	$236.50
6½" Dia.	$500.00
7" Dia.	$600.00

And every Fishing Jar Size at the Best Price.

Every Fishing Jar size as well as every Drilling Jar Size.
Acme Carbon Jars 6½" dia. and larger are made to heavy construction, similar to Acme Alloy Rein Type Jars, Fig. 107AA.
Acme Alloy Jars have more wearing stock than any other make.
All prices F.O.B. Factory, Parkersburg, W. Va.

Place your orders through your supply store or Dealer

PESA
PETROLEUM EQUIPMENT SUPPLIERS ASSOCIATION
PARTNERS IN PETROLEUM PROGRESS

Complete information on Jars and other Acme Drilling and Fishing Tools is available in a FREE CATALOGUE. For your Copy, consult your nearest ACME DEALER or write direct to:

Acme Fishing Tool Company

PARKERSBURG, W. VA.
ESTABLISHED 1900
Greatest Name in Cable Tools
Tool Plant Division: STARDRILL-KEYSTONE
EXPORT OFFICE Stardrill-Keystone Co., Beaver Falls, Pa.

since the dome itself proved to be outside the productive boundary of the reservoir, as indicated by the numerous dry holes shown just to the northeast of the reservoir in Figure 2.

The northeast or Driftwood end of this reservoir was discovered first. The discovery well was Sylvania's S. C. Eaton No. 1 (Figure 2, well 1-A) completed September 15, 1951. Since this well was situated relatively low on the southwest plunge of the Driftwood dome, subsequent tests were made high on the dome in and around the town of Driftwood, none of which proved productive apparently because of a tight sand stratigraphic closure at the northeast end of the reservoir. Development was then shifted down the plunge to the southwest.

The Keta Oil and Gas Company's Charleroi Mountain Club No. 1 (Figure 2, well 57-S) on the Benezette dome opened the Benezette end of the reservoir in December, 1952. Then in March, 1953, the Benezette Valley Development Company brought in the William Woodring No. 1 (Figure 2, well 69-F). This well was extremely important in that it is some 300 feet lower on the flanks of the Benezette dome than the Charleroi well, indicating that the Driftwood-Benezette field was much larger than had previously been estimated.[8] This led to the furious drilling race between private landowners which resulted in the dense well pattern as shown in Figure 2, areas F, G and H. Presumably, if the areas to the south had not been mostly state-owned land, the entire field would have been drilled into a similar pattern.

B. Drilling and Production Practices

1. Drilling and Gauging

Drilling operations reached a peak in August, 1953, when 22 producing wells were brought in. The rate then dropped slightly and leveled off at about fifteen to twenty wells per month until July, 1954, at which time there began a rapid decline in the drilling rate.

Most of the early drilling was with cable tools which averaged about sixty feet per day. Rotary drilling was later used, which averaged about 180 feet per day; however, lost circulation and completion problems were frequently caused by the high density (17 pounds per gallon) drilling mud. Completion problems were often overcome by drilling-in with cable tools, but a more recent practice of using air-rotary drilling with gas completions has been highly successful in eliminating both of these difficulties. The air-rotary has shown a penetration rate of about twice that of the regular rotary.[9]

All methods employ the practice of setting a seven-inch O. D. casing about ten feet into the Onondaga limestone, and then drilling a 6⅛-inch hole into or through the Oriskany sandstone.

Open-flow capacities of wells are measured with pitot tubes while the gas is discharged to the atmosphere. Shut-in pressures are generally recorded after wells have been closed in for 24 hours, although the rush to cut the wells into the pipeline frequently permits only a few hours shut-in time.

2. Production Practices

Little can be said of production practices except that wells are cut in to the pipeline as quickly as possible and permitted to flow at maximum rate. Figure 3 shows the cumulative production and production rate of the field plotted against time. The dotted portion of the curves represents the predicted recovery and recovery rates as explained in detail in Section V, C.

There has been no evidence of water drive during production from this field. There have been occasions of wells being drowned out by water, but this difficulty has frequently been relieved, at least temporarily or partially, by shutting in the wells for a few days.

IV. Determination of Reserves

An accurate determination of gas reserves in a reservoir can be made only when accurate reservoir pressures are known. Since the Driftwood-Benezette reservoir has never been shut in in order to determine a reservoir pressure, and since pressures for individual wells are not periodically recorded, any method used in computing reserves is largely guesswork. The original pressure was most probably about 4,020 pounds per

square inch gage, as measured at the well head. Obviously, no other pressure would be needed to compute reserves if the boundaries of the reservoir, the porosity, the per cent water saturation, and the sand thickness were known. However, in view of the highly faulted structure of this reservoir, the probable wide variation in porosity, and the doubtful boundaries as estimated, the only practicable method for determining reserves is by the use of declining reservoir pressures with cumulative production, as is shown graphically by Figure 4, and as explained in detail later in this section.

The only course for determining the average reservoir pressure lay in averaging pressures by areas, area pressures being obtainable from original pressures for new wells. It is believed that the boundaries of the reservoir are sufficiently well established so that it can be divided into areas as shown in Figure 2, and that each area has roughly the same average porosity and sand thickness. Though this may not be entirely true, the method of averaging area pressures in order to determine the over-all reservoir pressure is not overly demanding of an accurate reservoir area, and it is not necessary that the sand thickness or porosity be known, provided each area is assumed to have equal pore space. The reservoir area as shown is comprised of forty-one approximately equal-sized blocks of about one thousand acres each.

The only difficulty lay in determining the average area pressures at a selected date or dates. The pressure recorded for a well drilled in the area on or near the selected date could not be used with any degree of accuracy, for often the well would be in such close proximity to another that its pressure would be greatly affected, or the pressure shown for a well drilled at a later date in the same vicinity might have been considerably higher. Many additional factors had to be considered, such as the location of the wells in the area, their distance apart, the length of shut-in time compared to flow rate, and pressures in adjoining areas.

It soon became apparent that many recorded well pressures were lower than they should have been. Most of the wells were shut in for less than twenty-four hours when their pressures were recorded. This is far short of the time estimated to have been necessary for the pressure to stabilize in sand of such low permeability. It has been illustrated that pressures recorded after three days may still be well below the stabilized pressures.[10]

It was impossible to select any single date near which, during the early and late stages of development, wells were drilled in a majority of the areas. This required such an extensive use of estimated area pressures that little reliability could be placed in the computed average. It was, therefore, decided to determine the one most accurate average reservoir pressure which occurred well along in the productive life of the reservoir. Only one pressure, other than the original, is needed to compute reserves, and one good pressure is considered to be more accurate than a decline curve average of several poor ones. In order to determine the most accurate pressure each block area was considered separately. Again, weighing all significant

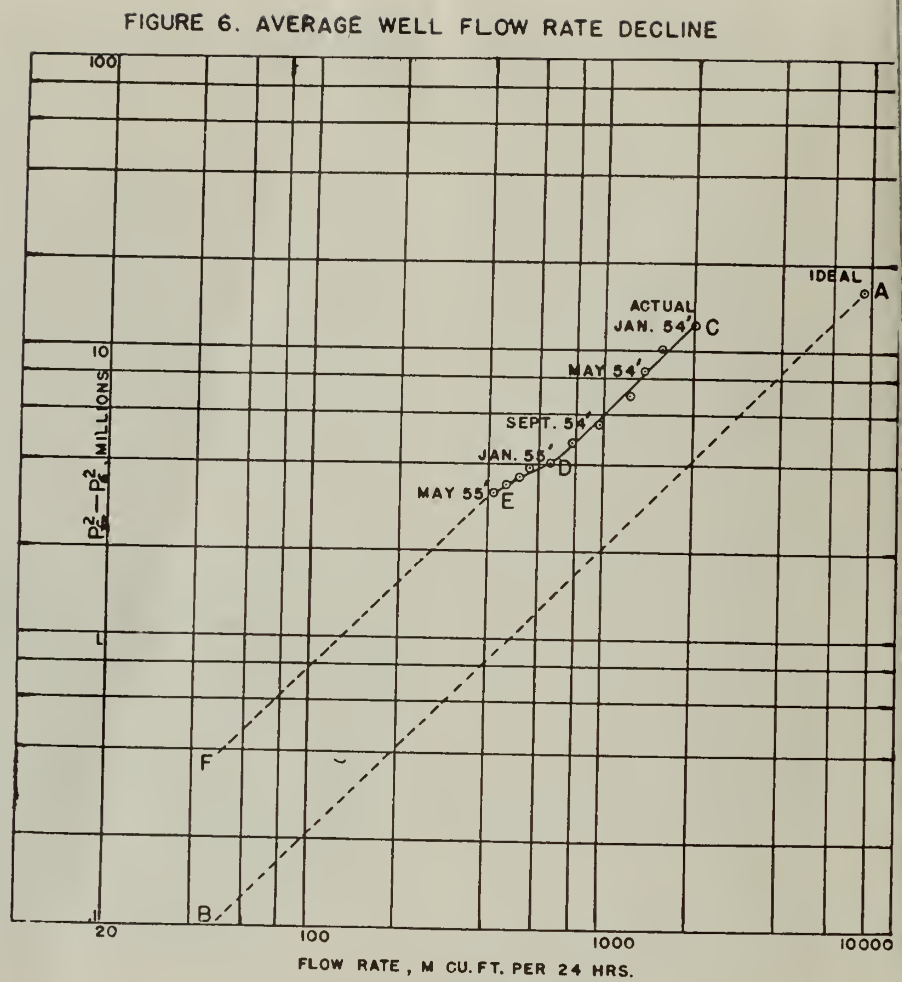


Figure 6—Average Well Flow Rate Decline

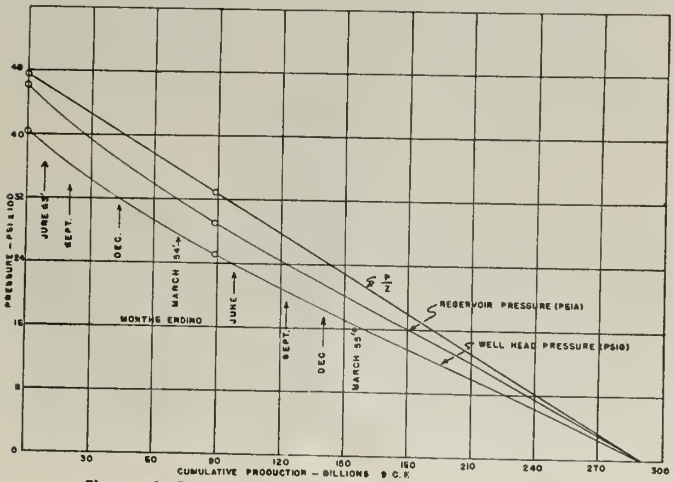


Figure 4—Pressure Decline with Cumulative Production

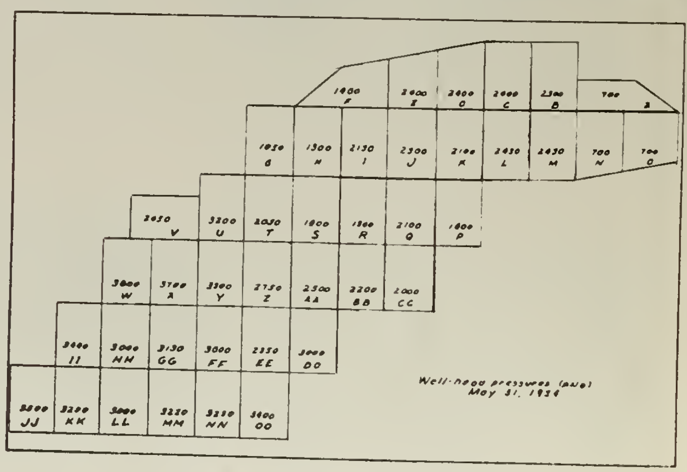


Figure 5—Pressures by Block Areas

factors stated above, every instance in which a well pressure or several well pressures appeared to reasonably represent that for the block area was recorded under the date shown. When such pressures for all areas had been recorded, the widest coverage of area pressures fell near the date of May 31, 1954. That date was, therefore, selected for determining the over-all average reservoir pressure. In cases where a block area failed to show a pressure on or near that date, it was possible to interpolate between dates on either side of May, 1954, or to estimate the area pressure from those shown for surrounding areas. Well-head pressures thus determined are shown in Figure 5. The average of these gage pressures came to 2,490 pounds per square inch.

The pressure due to the weight of the column of gas was computed using the equation

$$P_w = \frac{P_x ZRT\,144}{MH} - .5P_x^{*}$$

where

- P_w = well-head pressure in pounds per square inch absolute.
- P_x = pressure due to the weight of the gas column in pounds per square inch,
- Z = gas compressibility factor at average temperature in the well bore and at well-head pressure,
- R = gas constant,
- T = average temperature of the gas column,
- M = molecular weight of the gas,
- H = average depth of the reservoir below the surface.

If natural gas expanded upon release in pressure exactly in accordance with Boyle's law, the pressure decline curve would merely be a straight line through the original reservoir pressure and the May 31, 1954 reservoir pressure plotted against cumulative production as of May 31, 1954. However, since natural gas does not conform exactly to Boyle's law, the compressibility factor had to be considered. Calhoun shows that reservoir pressure (P) divided by the compressibility factor for the gas (Z) at reservoir conditions will plot as a straight line against cumulative production.[11] Compressibility factors were, therefore, computed for the two above reservoir pressures and a straight line plot made between the two P/Z points thus determined. The accuracy of the curve was checked analytically and original gas calculated to be 289 billion standard cubic feet. The reservoir pressures as they would be measured both in the reservoir and at the surface (Figure 4) were computed from the P/Z curves, using compressibility factors and values for the pressure due to the weight of the gas column as are shown graphically in Figures 7 and 8.

The 289 billion standard cubic feet of gas, as calculated to have been originally in the reservoir, at first appeared high, considering the present low production rate from the wells. An additional calculation was, therefore, made to determine the porosity of the sand, using 42,000 acres which has been estimated as the area of the reservoir, and an average sand thickness of 17 feet as estimated from the few well records showing this information. The porosity thus calculated came to 4.18 per cent. This porosity certainly does not appear to be excessive, considering the nine per cent and 8.34 per cent porosities found, respectively, for Oriskany sand samples blown from wells in the Tioga[12] and the Leidy gas fields.[13]

In consideration of the above, the 289 billion cubic feet does not appear to be excessive. An additional similar calculation of reserves was made, however, using the absolute minimum feasible pressures for block areas as of May 31, 1954. This calculation showed 255 billion standard cubic feet as the original gas content of the reservoir. The original calculation is considered to be the more accurate.

V. Operations

A. Determination of Average Well Productive Capacity

The equation $Q = C(P_f^2 - P_s^2)$ as described in the Bureau of Mines Monograph 7 is also applicable to groups of wells.[20] The average well productive capacity coefficient, C, may therefore be obtained by averaging the C's computed for each well by dividing Q by $(P_f^2 - P_s^2)^n$. Values for Q and for P_{wh} are known as

*Derived, using gas law equations, slightly inaccurate as the Z is based on the well-head pressure instead of the average pressure in the well.

each well is completed and an open flow test is made. Since the value of n was not known, it was necessary to average the production rates (Q) for wells producing under the same $(P_f^2-P_s^2)$. Further, since little confidence could be placed in the accuracy of the lower pressures, it was decided to use wells showing well-head pressures near 3,500 pounds per square inch. Thirty such wells showed an average Q of 7,300M cubic feet per day. The pressure due to the weight of the column of gas in these wells averaged about 500 pounds per square inch, bringing the P_f value to 4,000 pounds per square inch. Since P_s can be neglected for these large-hole high-pressure wells flowing against atmospheric pressure, 7,300 (Q) can be plotted against 16,000,000 $(P_f^2-P_s^2)$ on logarithmic paper as is shown by point A in Figure 6. This gives one point on the logarithmic plot, but does not of course show the slope of the line which can be used to determine values of Q at different values of $(P_f^2-P_s^2)$. It was decided to use an n value of one (viscous flow) in order to simplify calculations and to preclude the exaggeration of the adverse effects of production practices as is brought out in Section V, B and C. Using this n value of one, the coefficient (C) for the 30 wells came to .456. These values of C and n were justified by an average value of C equal to .45 for 127 wells on which the recorded data appeared to be the most accurate. The value of C for each individual well in this case was obtained by dividing the flow rate (Q) by $(P_f^2-P_s^2)$, P_f being the closed-in individual well-head pressure plus the pressure caused by the weight of the gas column, and P_s again neglected.

Readers might be interested in the calculation of average permeability where the value of C equal to .456 was substituted in the Darcy's law radial flow equation for viscous flow. Though a rough assumption had to be made for the drainage radius and though the flow may not be considered as radial in all cases, the computed permeability of 4.05 millidarcies as compared to the estimated permeability of ten millidarcies tends to substantiate the assumption that the value of C is not excessive. Two samples blown from wells in the Leidy gas field averaged 10.9 millidarcies.[21]

In consideration of the above, the curve AB in Figure 6 may be considered to represent the production rate that could have been expected from the average well with decreasing values of $(P_f^2-P_s^2)$ had the physical characteristics of the well and the producing formation remained constant, and had the wells been so spaced as to have the average formation pressure acting on each well.

B. Effect of Well Spacing and Production Practices on Production Rate

As pointed out in the previous section, curve AB (Figure 6) represents the declining production rates with declining $(P_f^2-P_s^2)$ values that could have been expected from average, undamaged, properly spaced wells. Curve CD (Figure 6) represents the actual average production rate per well with declining average reservoir pressures as shown in Figure 4. Points on curve CD were determined by dividing the total monthly production rates by the average number of producing wells as of the date indicated and plotting these rates per well against the $(P_f^2-P_s^2)$, P_f being considered as the formation pressure shown by Figure 4 and P_s being dependent upon the line pressure and is estimated as 600 pounds per square inch. The deficiency in production rate per well for any value of $(P_f^2-P_s^2)$ is represented by the horizontal distance between the two curves. This loss can be attributed to local pressure depletions in densely drilled areas and to physical damage to wells brought on by the rapid production rate.

Production losses caused by water coning, well caving, etc., cannot be well illustrated from the data available, although it would be a simple procedure to shut in wells occasionally and to plot the Q versus the $(P_f^2-P_s^2)$ on logarithmic paper. A line through successive points thus obtained would indicate whether or not a well is being damaged. A curve that bent toward the pressure axis would be indicative of water coning or other factors hindering deliverability. If only two points are available, and a line through the two points has a slope greater than one (more than 45 degrees to the pressure axis), it will, in the authors' opinion, be indication of well damage. This procedure was attempted for the few state wells on which records

could be found showing shut-in pressures sometime after their original gaging. However, curves thus obtained only served to prove the inadequacy and inaccuracy of recorded data. One curve showed a reverse slope, indicating lower flow rate with increasing formation pressure.

The Bureau of Mines back-pressure method for analyzing the deliverability of gas wells is a much more thorough and detailed procedure than that described above. Far greater benefits than that discussed above may also be derived from their method, although it requires the restricting of a well's flow for considerably more time than production practices in Pennsylvania permit.

C. Estimated Losses in Ultimate Recovery

Although it is impossible to predict the ultimate gas recovery from this reservoir with any degree of accuracy, it is fairly obvious in view of the declining production rate that an uneconomical production rate will be reached long before 289 billion cubic feet of gas have been produced.

Curve DE, Figure 6, shows a recent increasing rate of decline in production rate. This may be due to a variety of factors, such as

1. Water fingering cutting off relatively high pressure gas zones.
2. Water coning near the well bore, reducing the effective sand thickness.
3. Water condensation, reducing the effective permeability to the gas.
4. Water accumulation in the well bore.
5. Well caving.
6. Structural conditions within the reservoir.
7. The temporary shutting in of an increasing number of wells (since the rate is based on the number of producing wells as drilled rather than the actual number in operation).
8. Almost total pressure depletion in densely drilled areas.

It is the authors' opinion, however, that conditions in the reservoir may soon stabilize and that the flow rate after that time will continue in a directly proportional relationship with (P_f^2-P_s^2); at least this is the best that can be expected. This is illustrated by the curve EF, Figure 6. Though there is little chance that this curve will hold true to the abandonment date, it is not unreasonable to expect that it will hold approximately true for the next few years. This curve may be used in conjunction with the reservoir pressure curve (Figure 4) to provide a trial and error means for predicting future production and production rates. The dotted portions of the curves (Figure 3) were derived in this manner, considering a gradually decreasing value of P_s to zero in the year 1959. By the end of the year 1959 there should have been about 240 billion cubic feet of gas produced from this reservoir.

In consideration of curves AB and EF (Figure 6) and assuming a minimum economic flow rate (Q) of 50MCF per day at zero back pressure (P_s), the reservoir could be expected to be abandoned at an average pressure (P_f) of 632 pounds per square inch, whereas in the "ideal" case the abandonment pressure would be 316 pounds per square inch. This, according to Figure 4, reflects a loss of about 22 billion cubic feet of gas due to inefficient production practices.

Actually, it is anyone's guess as to just how far into the future this reservoir will produce gas at an economic rate. Most likely there will be numerous wells capable of producing gas at an economic rate for many years to come. It is highly probable, however, that water fingering and coning has or will cut off relatively high pressure zones within the reservoir, and that a reduced effective permeability to gas caused by water coning and condensation will seriously curtail production and reduce the ultimate recovery. An estimated loss of approximately 20 billion cubic feet of gas is considered to be conservative.

VI. Evaluation of Results

A. Operational Aspects

Although this study has developed no absolute proof that there will be substantial losses in ultimate recovery of gas from this reservoir, it does indicate that such losses are very likely and pre-

sents definite proof that a great amount of manpower and materials have been unnecessarily expended. Curves AB and CD (Figure 6) show that actual production per well was only about 35 per cent of what might have been expected from the properly-spaced average well, or that about one-third of the wells, if properly spaced and undamaged, should have given the same production rate. As was pointed out in Section V, A, this figure is based on a conservative estimate of the slope of the logarithmic curve AB (Figure 6) equal to one. It is possible that this curve could have had a slope of less than one, showing an increasingly wide separation between the "ideal" and "actual" curves with decreasing pressures, and therefore an increasingly poorer comparison of the actual well production rate with that of the ideal.

The ideal number of wells can only be determined by an economic balance of a great many factors, such as recoverable gas in place, drilling costs, back pressure required to prevent damaging the well or the producing formation, market demands and commitments and others. The back pressure required can be determined accurately by the Bureau of Mines method, but even this is subject to economic considerations. It may, for example, be more economical to permit minor damage to the well than to hold the back pressure sufficiently high to prevent damage entirely. Some states force the application of back pressure by restricting gas production to 25 per cent of open flow capacity. However, this restriction is also intended to prevent gas production in excess of market demands, and there is no reason known to the authors why Pennsylvania should restrict production to this rate if it can be shown that significant damage will not occur to wells producing at higher capacities. All of the above factors can best be weighed and applied through a unit operation plan, assisted perhaps by a well-spacing regulation.

It is probable that no more than two billion cubic feet per month would have been the ideal production rate from the Driftwood-Benezette field. Gas companies taking gas from this field must contract for vast quantities of gas from the Southwest to meet commitments during the winter months. Furthermore, the nature of pipeline operations as well as economic factors in the producing Southwest demand the establishment of long-term contracts with little or no seasonal variations in gas deliveries. This requires the delivery of large quantities of gas to this area during the summer months which must be stored in underground reservoirs. It is therefore obvious that the most economical rate to extract gas from this field would be a long-term rate necessary to augment deliveries from the Southwest with a minimum of storing required.

According to curve AB (Figure 6), two billion cubic feet per month could have been produced early in the productive life of the field (P_f = 4,600) with 27 wells producing at 25 per cent of open-flow capacity, and with 100 wells at this capacity five years later when the 120 billion cubic feet produced would have caused the reservoir pressure to drop to about 2,400 pounds per square inch (Figure 4). At 50 per cent open-flow capacity, only half of these wells would be required, and 100 wells would produce two billion cubic feet or more per month until 175 billion cubic feet of gas had been produced. Assuming that the flow rate could reach a maximum at the lower pressures without causing significant damage to the wells or the formation, 100 wells would sustain the 2 billion cubic feet per month rate for almost nine years or until 210 billion cubic feet of gas had been produced. Does not this appear more efficient and logical than has been the actual practice of drilling around 300 producing wells to obtain the flow rate shown in Figure 3?

The above comparison of actual practices with those which might have been employed under unit operations or under well spacing regulations does not show a comparison of ultimate recovery losses. It was illustrated in Section V, C that there should be at least 20 billion cubic feet of gas lost because of inefficient production practices. Though structural conditions in the reservoir might not permit such high ultimate recovery in either the actual or the ideal case, it is probable that unit operations or ade-

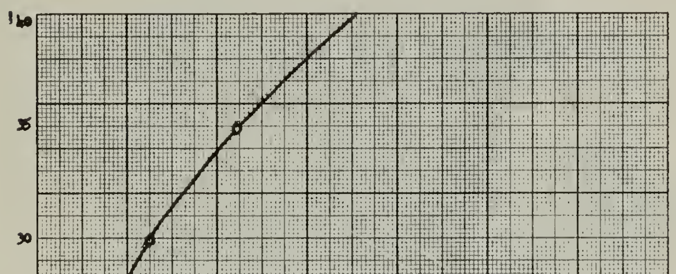


Figure 7—Compressibility factor vs. Pressure

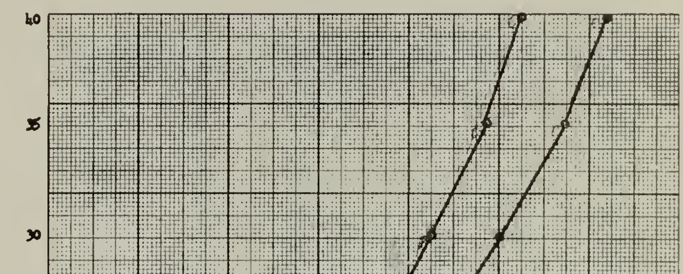


Figure 8—Pressure due to weight of gas column of well-head pressure

quate well spacing regulations would provide for more efficient exploration and thereby for a production rate closely approaching that shown by the curve AB (Figure 6).

B. Economic Aspects

1. General

The economic aspects of production practices may be illustrated roughly as follows:

(a) Before this reservoir is abandoned there will probably have been 300 producing wells drilled—200 more than is conservatively estimated to be the ideal as stated in the previous section. At $75,000 per well, this will amount to an unnecessary expenditure of $15,000,000.

(b) It is estimated that at least 60 billion cubic feet of gas will have been stored and re-extracted beyond that which would have been necessary at the two billion per month rate. At an estimated cost of five cents per thousand cubic feet for storing and re-extracting, this will amount to $3,000,000.

(c) Twenty billion cubic feet of gas estimated to be lost due to open flow production practices, at an estimated net value of about ten cents per M cubic feet[22] will amount to a loss of $2,000,000.

(d) It is estimated that about 75 billion cubic feet of gas would have increased in value by at least two cents per M cubic feet had it been possible to produce this gas on a seasonal contract or at a slower rate. This will amount to $1,500,000.

(e) There have been numerous relatively minor excessive expenditures, such as expenses for operating compressor stations, additional well maintenance costs due to open flow production practices, excess gathering lines, etc.

In view of the foregoing illustration, it is reasonable to assume that $20,000,000 have or will be wasted by the production practices employed in the Driftwood-Benezette gas reservoir. Furthermore, a large portion of these losses will be paid by the consumer in the form of high gas prices or in taxes to make up for the losses from state-owned tracts.

2. Private Landowners

Much of the land overlying this reservoir is privately owned small tracts of one acre or less. Such a landowner's fair share of the gas, considering 40,000 acres total and 280 billion cubic feet of gas as recoverable, is 7,000 M cubic feet. At one-eighth royalty this figure is further reduced to roughly 900 M cubic feet, which would amount to $247.50 at the current price of 27½ cents per M cubic feet. It is conservatively estimated that many small tract landowners have or will receive at least a hundred times this figure. Their excess profits obviously resulted in losses from less densely drilled areas, which in this field are mostly state-owned tracts.

Conclusion

It is concluded that there have been about 200 excess wells drilled in the Driftwood-Benezette field; that there could not possibly have been a fair and equitable distribution of the gas among the various landowners; that very probably there have or will be large quantities of gas left in the reservoir because of open-flow production practices; that sound engineering principles are not observed in gaging wells and in evaluating their performance, and that all of these are directly attributable to the lack of petroleum regulatory statutes in Pennsylvania. It is further concluded that the general public supports a large share of the inequities, gas losses and excess expenses either in higher gas prices or in decreased revenue from publicly owned land.

The obvious recommendation, therefore, is that the citizens of Pennsylvania demand the enactment of state statutes which will prevent this waste of manpower, materials, and petroleum resources, and which will insure the protection of correlative rights of landowners.

The details of the varied petroleum conservation measures and unitization statutes are beyond the scope of this paper. The average citizen, however, should not be so much concerned with these details as by the fact that nothing is being done to remedy the current inefficient and unfair production practices. Citizens should place their faith in an Oil and Gas Committee appointed for the purpose of recommending appropriate conservation and unitization statutes

and for enforcing the statutes after they are enacted. No person need fear monopolistic practices or the deprivation of his property without the due process of law. He is protected from these under federal law.

It is additionally recommended that the state immediately institute a program to acquire, compile and correlate information needed for accurate engineering studies, and to make this information readily available to all interested parties. No information relating to well production should be confidential. The very least that should be done is the enactment of a law requiring that all gas wells be shut in for a minimum of 48 hours once a year and that shut-in pressures be recorded and reported to an appropriate state regulatory body. Open-flow capacities, or flow rates against stated back pressures, should be recorded at the time wells are shut in, and likewise reported. Though this information will not suffice for accurate computation of the wells' performance by the Bureau of Mines back-pressure method, it will provide for considerably more accurate engineering studies than are currently possible. This recommendation would be superfluous if adequate petroleum conservation laws were enacted, for effective conservation presupposes a requirement for accurate knowledge of both the gas reservoir and the producing wells, which can only be gained from extensive and accurate data.

Acknowledgments

Grateful acknowledgment is made to the engineers and geologists of the Manufacturers Light and Heat Company and the New York State Natural Gas Company for their cordial reception of the authors in their quest for information and for their time and effort expended in making information available; to Professor H. G. Botset, Head of the Petroleum Engineering Department, University of Pittsburgh, for his helpful comments and recommendations; and to the U. S. Naval Postgraduate School, Monterey, California, for their sponsorship of the petroleum logistics curriculum at the University of Pittsburgh through which was provided the basic opportunity for preparing the Master of Science thesis of Commander C. B. Connally from which this paper was extracted.

BIBLIOGRAPHY

[1]Eckert, F. C., "Why We Should Have Regulated Well Spacing," PRODUCERS MONTHLY, November, 1954, p. 33.
[2]Wing, Robert C., "Pennsylvania Law," Prospective Unit Operation of Oil and Gas Reservoirs in Pennsylvania, (Master of Science thesis; University of Pittsburgh), 1952, pp. 11-13.
[3]"A Form for an Oil and Gas Conservation Statute," a Drafting Subcommittee of the Legal Committee. the Interstate Oil Compact Commission as amended May 5, 1950.
[4]Rawlins, E. L., and Schellhardt, M. A., "Back-Pressure Data on Natural-Gas Wells and Their Application to Production Practices." U. S. Bureau of Mines Monograph 7, (1935).
[5]Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 8.
[6]Bolger, Robert C., and Gouse, Harry V., "Surface and Subsurface Structure of the Driftwood Quadrangle Pennsylvania," Pennsylvania Topographic and Geologic Survey Bulletin M 36, 1953, p. 28.
[7]Fettke, C. R., "Structure Contour Maps of the Plateau Region of North-central and Western Pennsylvania," Pennsylvania Topograpphic and Geologic Survey Bulletin G-27 (1954), Plate 3, Northeast Sheet.
[8]Bolger, Robert C., "Geologic Structure of Parts of the Chestnut Ridge and Driftwood Anticlines," Pennsylvania Geologic Survey Progress Report 142, 1953.
[9]Wagner, H. J., "Lost Circulation and Completion Problems Eased." WORLD OIL, January, 1955, p. 116.
[10]Cornell, David, "How You Can Compute Gas Reserves More Accurately," WORLD OIL, December, 1952, p. 220.
[11]Calhoun, John C., "Example of Reserve Estimates by Gas Law," FFundamentals of Reservoir Engineering, University of Oklahoma Press, 1953, pp. 206-208.
[12]Fettke, Charles R., "Physical Characteristics of the Oriskany Sandstone," Pennsylvania Topographic and Geologic Survey Bulletin 102B, December, 1931, p. 2.
[13]Ebright, John R., and Ingham, Albert I., "Geology of the Leidy Gas Field and Adjacent Areas," Pennsylvania Topographic and Geologic Survey Bulletin M34, 1951, p. 19.
[14]Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 8.
[15]Rawlins, E. L., and Schellhardt, M. A., op. Cit., p. 79.
[16]Rawlins, E L., and Schellhardt, M. A., op. cit., p. 2.
[17]Schellhardt, M. A., "Application of the Back-Pressure Method for Determining Absolute Open Flows of Large Gas Wells," Bureau of Mines Report of Investigation 3767, August, 1944, p. 4.
[18]Muskat, M., and Botset, H. G., "Flow of Gas Through Porous Materials," PHYSICS, American Physical Society, Vol. 1, July, 1931, p. 40.
[19]Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 9.
[20]Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 103.
[21]Ebright, John R., and Ingham, Albert I., loc. cit.
[22]Eckert, F. C., op. cit., p. 34.
[23]"Recommended Practice for Determining Permeability of Porous Media," American Petroleum Institute, API RP 27, 1952, p. 23.

-32

GAU GAS FIELDS
LEG LEGISLATION
PEN PENNSYLVANIA

NEERING STUDY OF THE DRIFTWOOD-BENEZETTE GAS FIELD IN PENNSYLVANIA

by

Clem Brandon Connally

B.S., Agricultural and Mechanical College of Texas, 1938

Submitted to the Graduate School of the University of Pittsburgh in partial fulfillment of the requirements for the degree of Master of Science

Pittsburgh, Pennsylvania

1955

TABLE OF CONTENTS

28995

TABLE OF CONTENTS (Continued)

ILLUSTRATIONS

FOREWORD

This paper presents a petroleum engineering approach to the evaluation of production practices employed in the Driftwood-Benezette gas field in Pennsylvania, and compares the results of such practices with those which might have been accomplished had the field been developed and operated in the most efficient manner, or in accordance with modern petroleum conservation laws.

The Driftwood-Benezette gas field is important to this study only in that it provides a means for illustrating production practices generally employed in all Pennsylvania gas fields. Therefore, no attempt has been made to set forth details of engineering and geologic interest not closely related to production practices.

Grateful acknowledgment is made to the engineers and geologists of the Manufacturers Light and Heat Company and the New York State Natural Gas Company for their cordial reception of the author in his quest for information and for their time and effort expended in making information available; to Professor N. G. Botset, Head of the Petroleum Engineering Department, University of Pittsburgh, and Professor P. F. Fulton, Associate Professor, Petroleum Engineering Department, University of Pittsburgh, for the suggestion of the study and for their helpful comments and recommendations; and to the U. S. Naval Postgraduate School, Monterey, California, for their sponsorship of the petroleum logistics curriculum at the University of Pittsburgh through which the author was provided with the basic opportunity for preparing this paper.

I. INTRODUCTION

Petroleum production practices in Pennsylvania have remained the same in principle since the discovery of the Drake well in 1859. There are no laws restricting petroleum production even though it is a well known fact that "wide-open" flow may cause great underground losses of oil or gas; moreover, there are no laws protecting landowners' correlative rights -- the right to enjoy the use of one's property so long as this enjoyment does not do injury to others.[1]

There have been several proposals[2] for petroleum conservation laws which would require or encourage the development and operation of a petroleum reservoir as a single unit rather than on the wasteful and costly basis of "every man for himself." None has been enacted, however, and it appears that Pennsylvania may become the leading oil and gas producing state where no such laws are in effect. It is indeed a mystery why no such laws have been enacted. One would think that Pennsylvania, the founding state of the petroleum industry, would have been a leader in petroleum regulatory law. There must be some merit to petroleum conservation and unitization laws, for no state has ever repealed such a law. The Interstate Oil Compact Commission, which through engineering, research, and other committees functions to advise the various states on petroleum regulatory measures, has recommended the enactment of a unitization law.[3] Does it not seem logical that there should be a minimum waste of petroleum resources, and that a landowner should be permitted to recover his fair share of the oil or gas underlying his land, and only his fair share, without the drilling of unnecessary wells?

---

[1] References are listed in the Bibliography.

Perhaps many Pennsylvanians are not acutely aware of the waste of their petroleum resources or the infringement on their correlative rights caused by maximum-rate production practices employed in Pennsylvania. This study has been made in an attempt to illustrate, quantitatively, the effects of such practices as they relate to natural-gas production.

The Driftwood-Benezette field provides a good example for illustrating natural-gas production practices in Pennsylvania. This field was intensely drilled soon after its discovery and allowed to produce at maximum rate. Each landowner had to get his gas to the surface before his neighbor drained it away. It is the author's opinion that this caused the drilling of about 200 more wells than would have been necessary to produce the field efficiently, and that open-flow production will cause the underground loss of at least 20 billion cubic feet of gas, with a net value of approximately $2,000,000.

Unfortunately, accurate results cannot be obtained from the data available. Throughout this study, however, the author continually strove to favor the use of results and assumptions which would not exaggerate the adverse effects of existing production practices.

II. INADEQUACY OF ENGINEERING DATA

It became apparent at the beginning of this study that the lack of petroleum regulatory laws has resulted in an inadequacy of engineering data.

It is impossible for engineers to make accurate engineering studies, upon which plans for future gas production, transportation, storage and marketing must be based, without complete and accurate engineering information. Furthermore, this information must be readily available, at a central source, to all interested parties.

In 1935 the Bureau of Mines introduced a method for computing gas-well capacities and for applying this information to production practices.[4] The basic equation[5] set forth in that report is used throughout the natural gas producing industry—even in Pennsylvania—yet the data available on Pennsylvania wells for use in that equation are entirely inadequate for accurate calculations.

Though there are no laws preventing operators from obtaining these data on their own wells, few will voluntarily close in a well or restrict its production while their neighbor drains gas from under their land at a maximum rate. Further, in order to provide maximum benefit, this information must be standardized and compiled under a well organized program, enforced by a central authority and maintained readily available at a central source.

This lack of adequate information has obviously lead to inaccuracies in much of the data that have been obtained. Probably the greatest inaccuracies have been in measuring the shut-in pressures of the wells, the very heart of the information used in petroleum engineering studies.

II. INADEQUACY OF PRODUCTION DATA

It became apparent in the beginning of this study that the lack of petroleum regulatory laws has resulted in an inadequacy of engineering data.

It is imperative for engineers to have accurate and adequate records, upon which plans for future gas production, transportation, storage and marketing must be based, through analysis and economic evaluation, inter-action. Furthermore, this information must be regularly available, with eyeball records, to all interested persons.

In 1935 the Bureau of Mines introduced a method for recording reservoir information and for applying this information to production practices.[4] The basic equation[5] set forth in that report is most thorough and the results are generally satisfactory—except in reservoirs—but the data available in Pennsylvania needed for use in this equation are entirely inadequate for accurate calculation.

Though there are no laws presently governing the collection of data on rocks and wells, the well operators should be made to obtain the information which other engineers desire and that making their lack of a dependable value. However, in order to provide reliable results, this information must be standardized and compiled under a well organized program, enforced by a central authority and maintained readily available to a central source.

This lack of adequate information has previously led to inadequacies in each of the data that have been obtained. Possibly the greatest inaccuracies have been in regarding the back-in pressures of the wells, the very basis of the information used in petroleum engineering studies.

Another source of difficulty to an engineer is the confidential nature of production information on privately owned wells. An accurate evaluation of a well's performance requires the comparison of that well with other wells in the near vicinity, and an evaluation of the reservoir as a whole may require the use of performance data on any well in the reservoir.

Specific examples of either inadequate or inaccurate information encountered during the course of this study are listed as follows:

1. Shut-in well pressures are often inaccurate. Most wells were shut in for less than 24 hours when their pressures were recorded, some for only an hour or less.

2. The entire reservoir has never been shut in and the average pressure recorded, nor are individual wells shut in periodically for this purpose. One accurate reservoir pressure, after sufficient gas had been produced to show a pressure decline, would have been sufficient to compute total gas reserves. As the situation stands, operators are merely guessing at gas reserves, and no one will ever know how much gas is lost due to production practices.

3. Production information on privately owned land is confidential and, therefore, not available to the public or to all interested producing companies.

4. No records could be found showing shut-in pressures for wells on more than one occasion after having been cut in to the pipeline. This information is necessary in order to determine a well's performance characteristics and behavior as described in Section V, A and B.

5. No one producer or regulatory body has all the data on all the wells in the reservoir. Absence of monthly production rates for all wells

is the most important example of this inadequacy. Other missing information might be as follows: The drilling method used, whether or not a well was shot, original well-head pressures and shut-in time, and whether or not a well had been abandoned.

6. The reservoir temperature has never been measured.

7. Very few reservoir sand thicknesses have been recorded.

8. Well locations are not recorded in a standard form.

9. Neither the porosity nor the permeability of the sand have ever been measured.

In view of the above, the results brought out in this study are not nearly so accurate nor significant as they otherwise might have been. Perhaps the inadequacy of this study will serve to indicate the necessity for such state statates as will provide for the compilation of information necessary to conduct accurate engineering studies.

III. HISTORY OF OPERATIONS

A. The Reservoir

The Driftwood-Benezette gas field is the largest known gas field in Pennsylvania, covering about 42,000 acres in Elk, Cameron, and Clearfield counties. Production is from the highly faulted Oriskany sandstone, which in this area is mostly "medium-grained, light gray, quartzose, slightly calcareous."[6] The Oriskany is capped by the Onondaga limestone formation.

Figure 1 shows the approximate area of the reservoir superimposed on a contour map on the Oriskany sandstone as constructed by Fettke.[7] Figure 2 shows locations of all wells numbered in the sequence in which they were completed or drilling operations abandoned, although numbers for dry holes have been omitted on the drawing. Pertinent information on each producing well is shown in Appendix I.

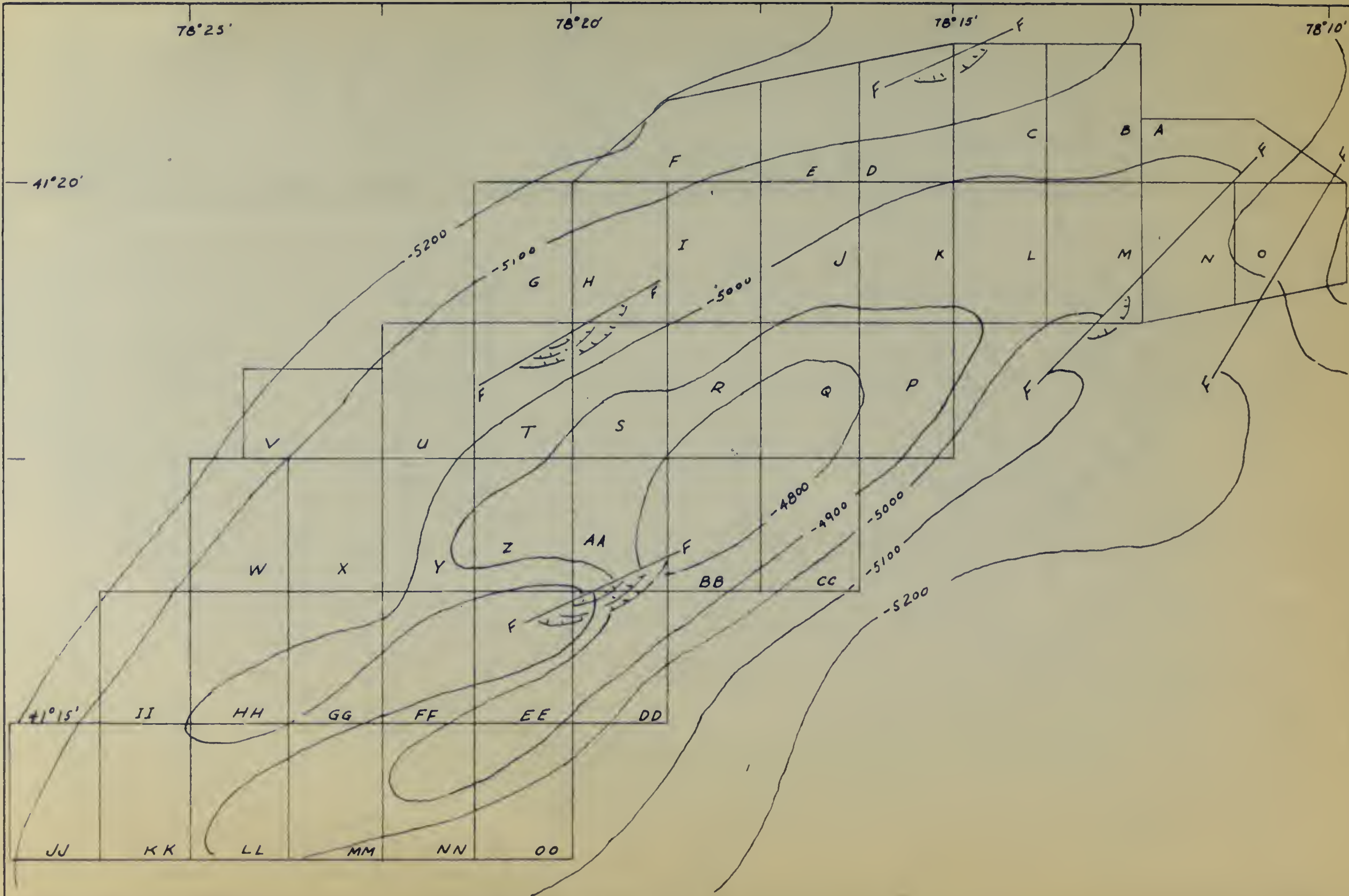
It should not be construed that the reservoir has such a jagged boundary as is indicated by the block areas in Figures 1 and 2. These blocks established by the author were used to compute the average reservoir pressure as described in Section IV.

This field is located on the Driftwood anticline, the highest point on which is the Driftwood dome, located about one mile northeast of the town of Driftwood. This dome is not shown in Figure 1 since the dome itself proved to be outside the productive boundary of the reservoir, as indicated by the numerous dry holes shown just to the northeast of the reservoir in Figure 2.

The northeast or Driftwood end of this reservoir was discovered first. The discovery well was Sylvania's S. C. Eaton No. 1 (Figure 2,

well 1-A) completed September 15, 1951. Since this well was situated relatively low on the southwest plunge of the Driftwood dome, subsequent tests were made high on the dome in and around the town of Driftwood, none of which proved productive apparently because of a tight sand stratigraphic closure at the northeast end of the reservoir. Development was then shifted down the plunge to the southwest.

The Keta Oil and Gas Company's Charleroi Mountain Club No. 1 (Figure 2, well 57-S) on the Benezette dome opened the Benezette end of the reservoir in December, 1952. Then in March, 1953, the Benezette Valley Development Company brought in the William Woodring No. 1. (Figure 2, well 69-F) This well was extremely important in that it is some 300 feet lower on the flanks of the Benezette dome than the Charleroi well, indicating that the Driftwood-Benezette field was much larger than had previously been estimated.[8] This led to the furious drilling race between private landowners which resulted in the dense well pattern as shown in Figure 2, areas F, G and H. Presumably, if the areas to the south had not been mostly state-owned land, the entire field would have been drilled into a similar pattern.



Contours on Oriskany Sandstone

Figure 1 Structure Map Driftwood-Benezette Gas Field

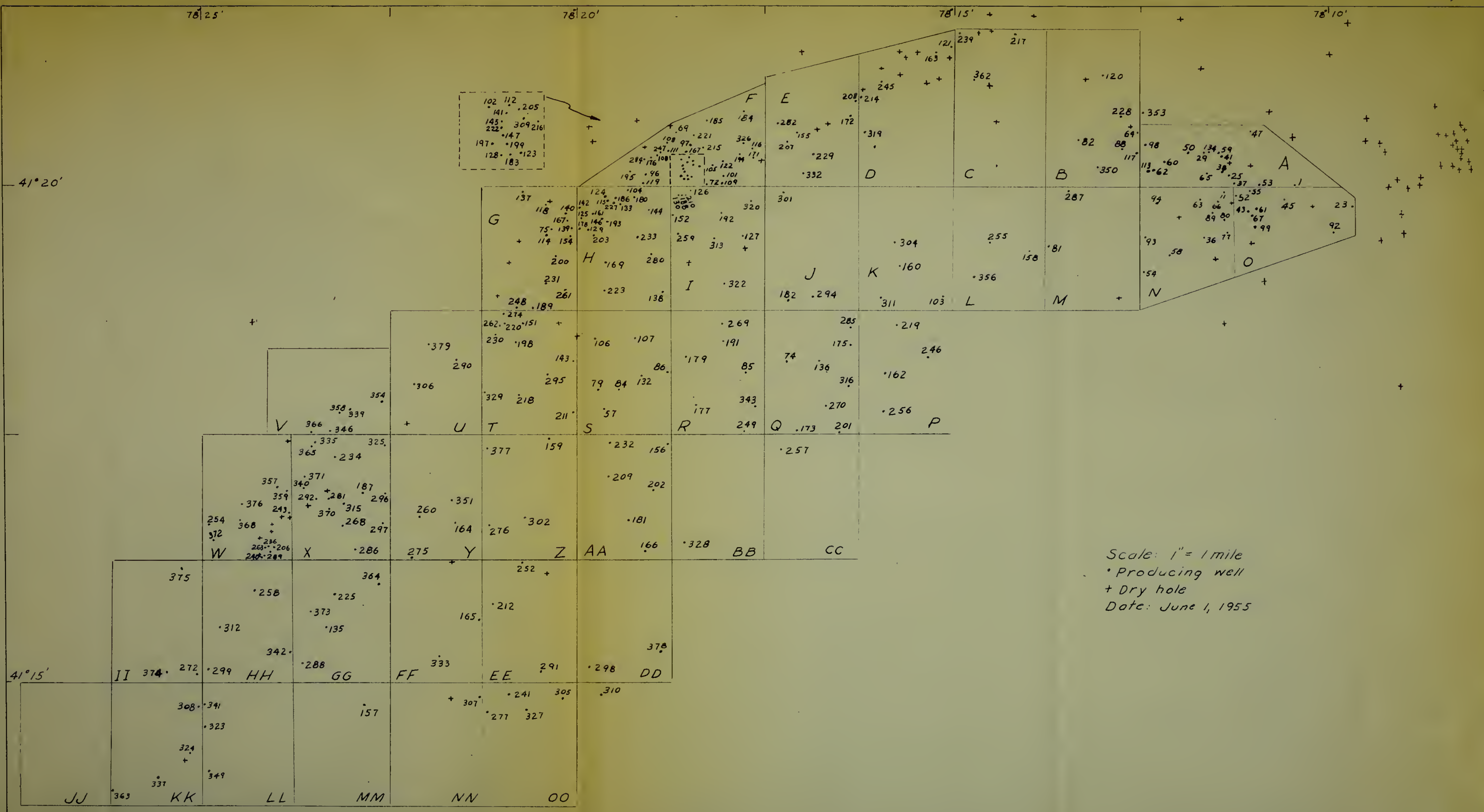


Figure 2. Block Area Map, Driftwood-Benezette Gas Field

B. Drilling and Production Practices

1. Drilling and Gaging

Drilling operations reached a peak in August, 1953 when 22 producing wells were brought in. The rate then dropped slightly and leveled off at about fifteen to twenty wells per month until July, 1954, at which time there began a rapid decline in the drilling rate. Appendix IV shows a detailed breakdown of the wells by months.

Most of the early drilling was with cable tools which averaged about sixty feet per day. Rotary drilling was later used, which averaged about 180 feet per day; however, lost circulation and completion problems were frequently caused by the high density (17 pounds per gallon) drilling mud. Completion problems were often overcome by drilling-in with cable tools, but a more recent practice of using air-rotary drilling with gas completions has been highly successful in eliminating both of these difficulties. The air-rotary has shown a penetration rate of about twice that of the regular rotary.[9]

All methods employ the practice of setting a seven-inch O. D. casing about ten feet into the Onondaga limestone, and then drilling a 6 1/8 inch hole into or through the Oriskany sandstone.

Open-flow capacities of wells are measured with pitot tubes while the gas is discharged to the atmosphere. Shut-in pressures are generally recorded after wells have been closed in for 24 hours, although the rush to cut the wells into the pipeline frequently permits only a few hours shut-in time.

2. Production Practices

Little can be said of production practices except that wells are cut in to the pipeline as quickly as possible and permitted to flow at

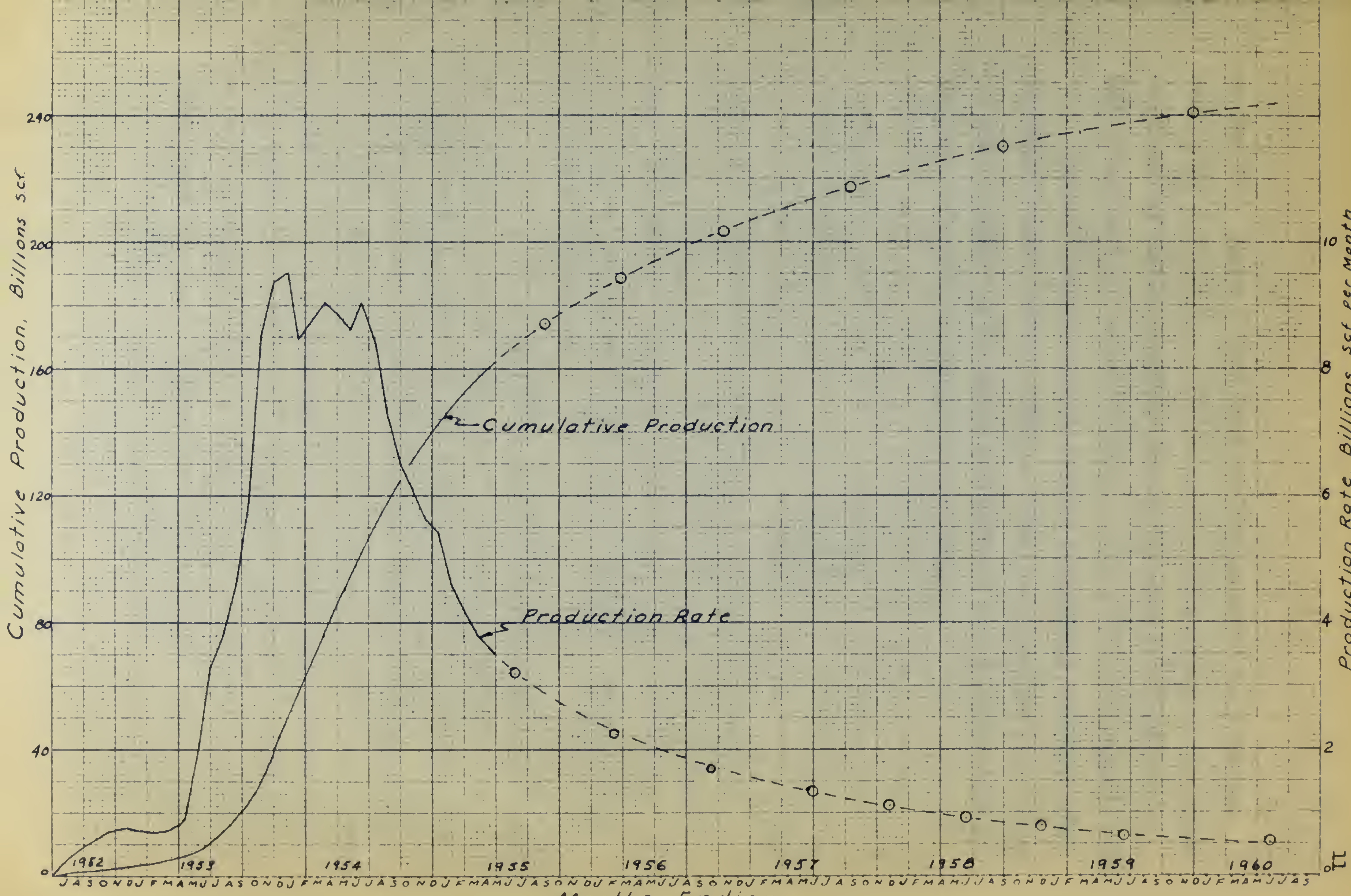


Figure 3. Cumulative Production & Production Rate vs. Time

maximum rate. Figure 3 shows the cumulative production and production rate of the field plotted against time. The dotted portion of the curves represents the predicted recovery and recovery rates as explained in detail in Section V, C. Actual production figures are shown in Appendix III.

There has been no evidence of water drive during production from this field. There have been occasions of wells being drowned out by water, but this difficulty has frequently been relieved, at least temporarily or partially, by shutting in the wells for a few days.

IV. DETERMINATION OF RESERVES

An accurate determination of gas reserves in a reservoir can be made only when accurate reservoir pressures are known. Since the Driftwood-Benezette reservoir has never been shut in, in order to determine a reservoir pressure, and since pressures for individual wells are not periodically recorded, any method used in computing reserves is largely guesswork. The original reservoir pressure was most probably about 4020 pounds per square inch gage, as measured at the well head. Obviously, no other pressure would be needed to compute reserves if the boundaries of the reservoir, the porosity, the per cent water saturation, and the sand thickness were known. However, in view of the highly faulted structure of this reservoir, the probable wide variation in porosity, and the doubtful boundaries as estimated, the only practicable method for determining reserves is by the use of declining reservoir pressures with cumulative production, as is shown graphically by Figure 4, and as explained in detail later in this section.

The only course for determining the average reservoir pressure lay in averaging pressures by areas, area pressures being obtainable from original pressures for new wells as shown in Appendix I. It is believed that the boundaries of the reservoir are sufficiently well established so that it can be divided into areas as shown in Figure 2, and that each area has roughly the same average porosity and sand thickness. Though this may not be entirely true, the method of averaging area pressures in order to determine the over-all reservoir pressure is not overly demanding of an accurate reservoir area, and it is not necessary that the sand thickness or porosity be known, provided each area is assumed to have equal pore

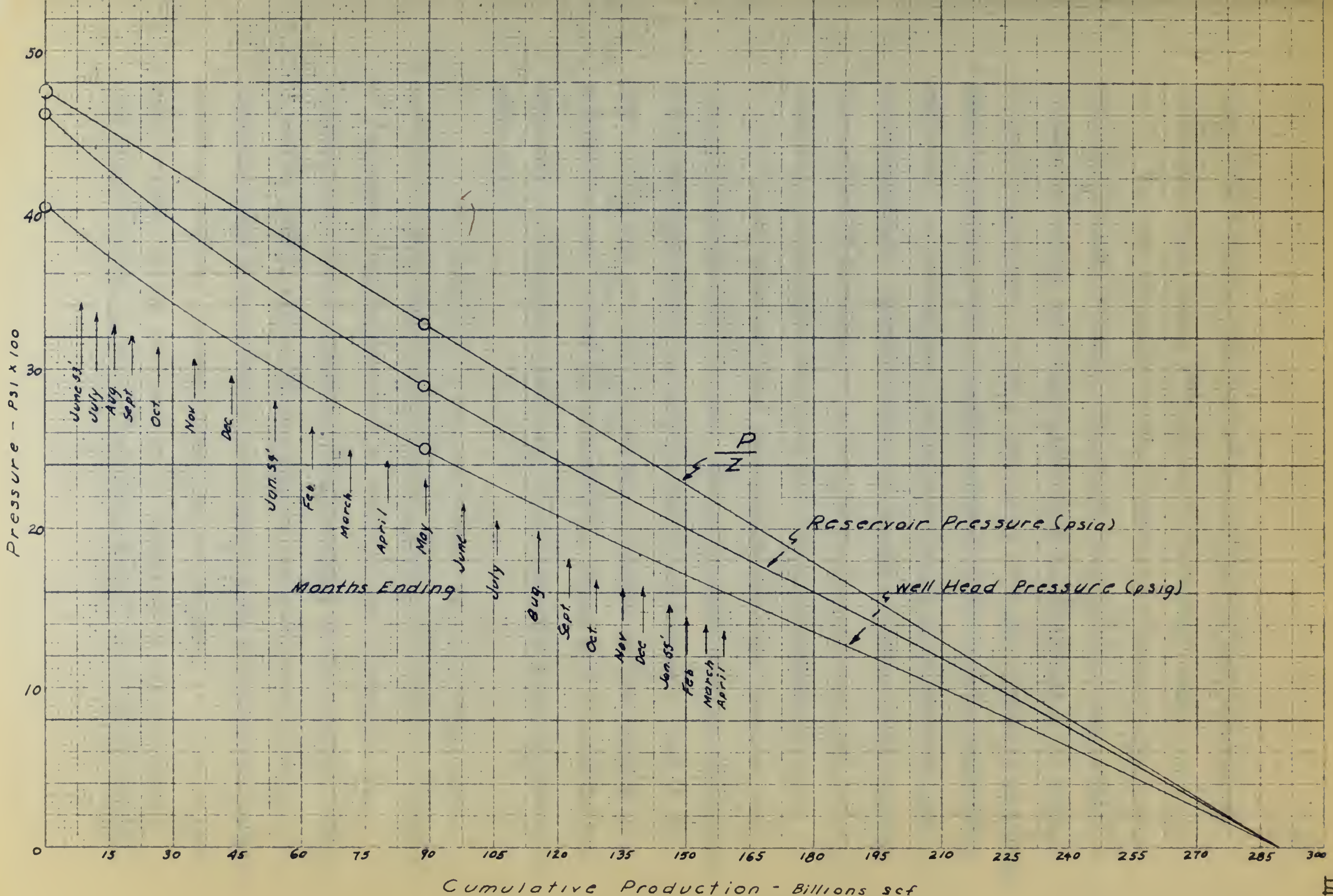


Figure 4. Pressure Decline with Cumulative Production

space. The reservoir area as shown is comprised of forty-one approximately equal-sized blocks of about one thousand acres each.

The only difficulty lay in determining the average area pressures at a selected date or dates. The pressure recorded for a well drilled in the area on or near the selected date could not be used with any degree of accuracy, for often the well would be in such close proximity to another that its pressure would be greatly affected, or the pressure shown for a well drilled at a later date in the same vicinity might have been considerably higher. Many additional factors had to be considered, such as the location of the wells in the area, their distance apart, the length of shut-in time compared to flow rate, and pressures in adjoining areas.

It soon became apparent that many recorded well pressures were lower than they should have been. Most of the wells were shut in for less than twenty-four hours when their pressures were recorded. This is far short of the time estimated to have been necessary for the pressure to stabilize in sand of such low permeability. It has been illustrated that pressures recorded after three days may still be well below the stabilized pressures.[10]

It was impossible to select any single date near which, during the early and late stages of development, wells were drilled in a majority of the areas. This required such an extensive use of estimated area pressures that little reliability could be placed in the computed average. It was, therefore, decided to determine the one most accurate average reservoir pressure which occurred well along in the productive life of the reservoir. Only one pressure, other than the original, is needed to compute reserves, and one good pressure is considered to be more accurate than a decline curve average of several poor ones. In order to determine

the most accurate pressure each block area was considered separately. Again, weighing all significant factors stated above, every instance in which a well pressure or several well pressures appeared to reasonably represent that for the block area was recorded under the date shown. When such pressures for all areas had been recorded, the widest coverage of area pressures fell near the date of May 31, 1954. That date was, therefore, selected for determining the over-all average reservoir pressure. In cases where a block area failed to show a pressure on or near that date, it was possible to interpolate between dates on either side of May, 1954 or to estimate the area pressure from those shown for surrounding areas. Well-head pressures thus determined are shown in Figure 5. The average of these gage pressures came to 2490 pounds per square inch.

The pressure due to the weight of the column of gas was computed as shown in Appendix II, using the equation

$$Pw = \frac{P_x 2RT\ 144}{MH} - .5Px\ ^*$$

where Pw = well head pressure in pounds per square inch absolute,

P_x = pressure due to the weight of the gas column in pounds per square inch,

Z = gas compressibility factor at average temperature in the well bore and at well head pressure,

R = gas constant,

T = average temperature of the gas column,

M = molecular weight of the gas,

H = average depth of the reservoir below the surface.

*Derived, using gas law equations, slightly inaccurate as the Z is based on the well head pressure instead of the average pressure in the well.

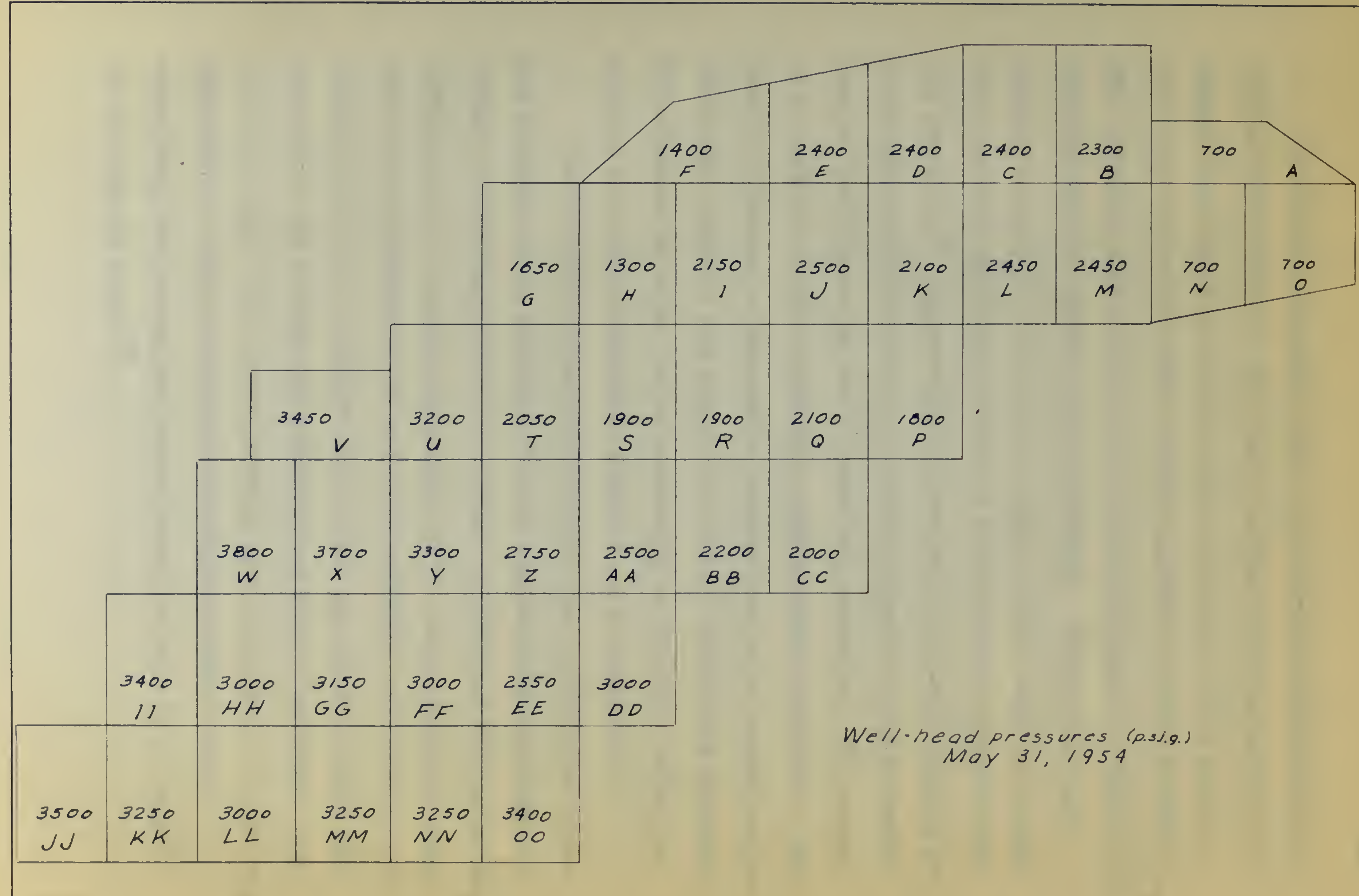


Figure 5. Pressures by Block Areas

If natural gas expanded upon release in pressure exactly in accordance with Boyle's law, the pressure decline curve would merely be a straight line through the original reservoir pressure and the May 31, 1954 reservoir pressure plotted against cumulative production as of May 31, 1954. However, since natural gas does not conform exactly to Boyle's law, the compressibility factor had to be considered. Calhoun shows that reservoir pressure (P) divided by the compressibility factor for the gas (Z) at reservoir conditions will plot as a straight line against cumulative production.[11] Compressibility factors were, therefore, computed for the two above reservoir pressures as shown in Appendix II and a straight line plot made between the two P/Z points thus determined. The accuracy of the curve was checked analytically, also as shown in Appendix II. The reservoir pressures as they would be measured both in the reservoir and at the surface (Figure 4) were computed from the P/Z curve, using compressibility factors and values for the pressure due to the weight of the gas column as are shown graphically in Figures 7 and 8, Appendix II.

The 239 billion standard cubic feet of gas, as calculated to have been originally in the reservoir, at first appeared high, considering the present low production rate from the wells. An additional calculation was, therefore, made to determine the porosity of the sand, using 42,000 acres which has been estimated as the area of the reservoir, and an average sand thickness of 17 feet as estimated from the few well records showing this information. The porosity thus calculated, as shown in Appendix II came to 4.18 per cent. This porosity certainly does not appear to be excessive, considering the nine per cent and 8.34 per cent porosities found, respectively, for Oriskany sand samples blown from wells in the Tioga[12] and the Leidy gas fields.[13]

In consideration of the above, the 289 billion cubic feet does not appear to be excessive. An additional similar calculation of reserves was made, however, using the absolute minimum feasible pressures for block areas as of May 31, 1954. This calculation showed 255 billion standard cubic feet as the original gas content of the reservoir. The original calculation is considered to be the more accurate.

V. OPERATIONS

A. Determination of Average Well Productive Capacity

1. Bureau of Mines Equation

The Bureau of Mines has reported[14] that:

> "For normal gas wells there is a consistent relationship between rates of delivery of gas and corresponding pressures when the pressures in the sand are used as the basis for interpretation. Results of tests throughout the United States show that when the rates of delivery are plotted on logarithmic paper against $(P_f^2 - P_s^2)$ - the respective differences of the squares of the formation pressure, P_f and the pressure at the sand face, P_s - the relationship is represented by a straight line, which may be expressed mathematically by the formula
>
> $$Q = C(P_f^2 - P_s^2)^n$$
>
> where Q = rate of flow, M cubic feet per 24 hours,
>
> C = coefficient,
>
> P_f = "shut-in" formation pressure, pounds per square inch absolute,
>
> n = exponent, corresponding to the slope of the straight line relationship between Q and $(Pf^2 - Ps^2)$ plotted on logarithmic paper."

It is further pointed out in that report[15] that the value of n, or the slope of the logarithmic plot, would remain constant if no physical changes occurred in the well bore or in the producing formation which affected the productive capacity of the well.

This Bureau of Mines report recommends the above relationship as a means for analyzing the deliverability of gas wells. The procedure involves, essentially, the periodic shutting in of the well to determine the formation pressure (P_f), and then permitting the well to flow at decreasing back pressures (P_s) during which time the rate of flow (Q) is measured

for each back pressure. The logarithmic plot described above can be extrapolated to determine the open flow capacity of the well without the necessity of venting the well to the atmosphere and thereby wasting gas and probably damaging the well.[16] When flow rates so determined at periodic intervals fail to fall on the same straight-line logarithmic plot, it is indicative of changes occurring in the well or the producing formation, such as water coning, water condensation, well caving, etc. This procedure also provides a means for predicting flow rates at various back pressures and formation pressures, and for analyzing the effects of measures taken to increase a well's productive capacity.

A Bureau of Mines report[17] some nine years later carried an interesting discussion of the value of n as related to a similar exponent in an equation[18] for isothermal flow derived and confirmed experimentally by Muskat and Botset, where the latter had shown, in effect, that the value of n in the equation $Q = C(P_f^2-P_s^2)^n$ would range from 0.5 for wholly turbulent flow to 1.0 for wholly viscous flow. The Bureau of Mines report stated that it had been shown experimentally that the value of n ranged from 0.6 to 1.2 and that there was no significant bending of the logarithmic plot toward the pressure axis for increased values of $(P_f^2-P_s^2)$ and Q, as might have been expected.

It is significant to note, however, that the second Bureau of Mines report was based largely on results of tests set forth in the first report and that both field and experimental results[19] were obtained from highly permeable sands through which gas was flowing under relatively low pressures. It is further significant to note that many laboratory tests did show logarithmic plots that bent slightly toward the pressure axis with increasing values of Q and $(P_f^2-P_s^2)$, and that there appears to be

no confirmation in laboratory tests for values of n greater than one. One might, therefore, surmise that possibly there could be a significant bending of the logarithmic curve toward the pressure axis with greatly increasing values of $(P_f^2-P_s^2)$ and Q and that possibly the few cases during field tests where the value of n exceeded one resulted from physical changes occurring in the well bore or from inaccurate data. It is the author's opinion that values of n greater than one should be accepted with reservations, if at all.

2. Application of the Bureau of Mines Equation

The equation $Q = C(P_f^2-P_s^2)$ as previously described is also applicable to groups of wells.[20] The average well productive capacity coefficient C, may therefore be obtained by averaging the C's computed for each well by dividing Q by $(P_f^2-P_s^2)^n$. Values for Q and for P_f as measured at the well head are shown in Appendix I. Since the value of n was not known, it was necessary to average the production rates (Q) for wells producing under the same $(P_f^2-P_s^2)$. Further, since little confidence could be placed in the accuracy of the lower pressures, it was decided to use wells showing well-head pressures near 3500 pounds per square inch. Thirty such wells showed an average Q of 7300 M cubic feet per day. The pressure due to the weight of the column of gas in these wells averaged about 500 pounds per square inch, bringing the P_f value to 4000 pounds per square inch. Since P_s can be neglected for these large-hole high-pressure wells flowing against atmospheric pressure, 7300 (Q) can be plotted against 16,000,000 $(P_f^2-P_s^2)$ on logarithmic paper as is shown by point A in Figure 6. This gives one point on the logarithmic plot, but does not of course show the slope of the line which can be used to determine values of Q at different values of $(P_f^2-P_s^2)$. It was decided to use an n value of one (viscous flow) in order to simplify calculations and to preclude the exaggeration

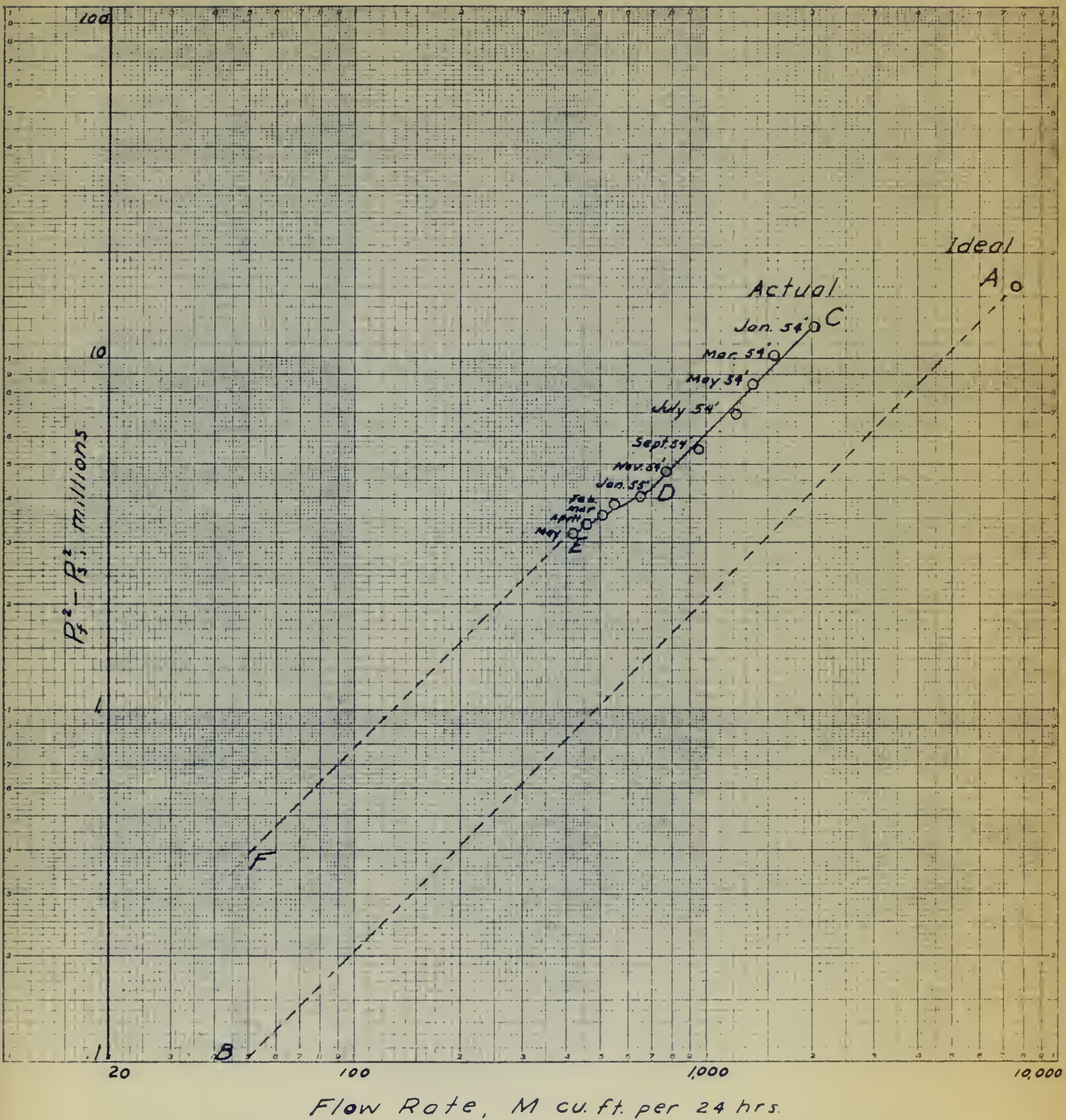


Figure 6. Average Well Flow Rate Decline

of the adverse effects of production practices as is brought out in Section V, B and C. Using this n value of one, the coefficient (C) for the 30 wells came to .456. These values of C and n were justified by an average value of C equal to .45 for 127 wells on which the recorded data appeared to be the most accurate. The value of C for each individual well in this case was obtained by dividing the flow rate (Q) by $(P_f^2-P_s^2)$, P_f being the closed-in individual well-head pressure plus the pressure caused by the weight of the gas column, and P_s again neglected.

Readers might be interested in the calculation of average permeability as shown in Appendix II where the value of C equal to .456 was substituted in the Darcy's law radial flow equation for viscous flow. Though a rough assumption had to be made for the drainage radius and though the flow may not be considered as radial in all cases, the computed permeability of 4.05 millidarcies as compared to the estimated permeability of ten millidarcies tends to substantiate the assumption that the value of C is not excessive. Two samples blown from wells in the Leidy gas field averaged 10.9 millidarcies.[21]

In consideration of the above, the curve AB in Figure 6 may be considered to represent the production rate that could have been expected from the average well with decreasing values of $(P_f^2-P_s^2)$ had the physical characteristics of the well and the producing formation remained constant, and had the wells been so spaced as to have the average formation pressure acting on each well.

B. Effect of Well Spacing and Production Practices on Production Rate

As pointed out in the previous section, curve AB (Figure 6) represents the declining production rates with declining $(P_f^2-P_s^2)$ values that could have been expected from average, undamaged, properly spaced wells. Curve CD (Figure 6) represents the actual average production rate per well with declining average reservoir pressures as shown in Figure 4. Points on curve CD were determined by dividing the total monthly production rates (Appendix III) by the average number of producing wells as of the date indicated (Appendix IV) and plotting these rates per well against the $(P_f^2-P_s^2)$, P_f being considered as the formation pressure shown by Figure 4 and P_s being estimated as 600 pounds per square inch. The deficiency in production rate per well for any value of $(P_f^2-P_s^2)$ is represented by the horizontal distance between the two curves. This loss can be attributed to local pressure depletions in densely drilled areas and to physical damage to wells brought on by the rapid production rate.

Losses in production rate resulting from dense well spacing and consequent local pressure depletions can be well illustrated by considering areas F, G, and H in Figure 2, where on May 31, 1954 some 73 wells were producing under a formation pressure of about 1700 pounds per square inch. If the back pressure at the sand face was 600 pounds per square inch, the production rate per well expressed as a per cent of the production rate which would have been attained under the average reservoir pressure of 2895 pounds per square inch at that time was

$$\frac{(1700^2-600^2)(100)}{(2895^2-600^2)} = 31.5 \text{ per cent}$$

Actually the formation pressure acting on many of the wells was probably considerably less than the average for the area. It is therefore obvious

5. Effect of Well Spacing and Production Practices on Production Rate

As pointed out in the preceding section, Curve II (Figure 6) relates the producing production rates with variations ($P_s^2 - P_w^2$) values that would have been expected from uniform, unrestricted, properly spaced wells. Curve III (Figure 6) represents the actual average production rate per well with declining average reservoir pressures as shown in Figure 4. Points of curve III were determined by dividing the total monthly production rates (Appendix III) by the average number of producing wells as of the date (Appendix IV) and plotting these rates per well against the ($P_s^2 - P_w^2$), P_s being determined as the formation pressure given by Figure 4 and P_w being estimated as 400 pounds per square inch. The difference in production rate per well for any value of ($P_s^2 - P_w^2$) is represented by the horizontal distance between the two curves. This loss can be attributed to local pressure depletion in closely drilled areas and to physical damage to sands brought on by the excess production rates.

Losses in production rate resulting from close well spacing and consequent local pressure depletions can be well illustrated by considering areas B, C, and E in Figure 4. Since in [illegible] [illegible] wells were producing under a formation pressure of about [illegible] pounds per square inch. If the back pressure at the sand face was 400 pounds per square inch, the production rate per well calculated as a per cent of the production rate which would have been obtained under the average reservoir pressure of [illegible] pounds per square inch at that time was

$$\frac{([illegible]^2-400^2)(100)}{([illegible]^2-400^2)} = [illegible] \text{ per cent}$$

Actually the formation pressure acting on many of the wells was probably considerably less than the average for the area. It is therefore evident

that a well drilled in this area at that time produced gas at less than one-third the rate that could have been expected of it had unit operation been in effect, or that the same total production rate for this area could have been achieved with less than one-third of the wells.

Production losses caused by water coning, well caving, etc. cannot be well illustrated from the data available, although it would be a simple procedure to shut in wells occasionally and to plot the Q versus the $(P_f^2-P_s^2)$ on logarithmic paper. A line through successive points thus obtained would indicate whether or not a well is being damaged. A curve that bent toward the pressure axis would be indicative of water coning or other factors hindering deliverability. If only two points are available, and a line through the two points has a slope greater than one (more than 45 degrees to the pressure axis), it will, in the author's opinion, be a positive indication of well damage. This procedure was attempted for the few state wells on which records could be found showing shut-in pressures sometime after their original gaging. However, curves thus obtained only served to prove the inadequacy and inaccuracy of recorded data. One curve showed a reverse slope, indicating lower flow rate with increasing formation pressure.

The Bureau of Mines back-pressure method for analysing the deliverability of gas wells, as described briefly in Section V, A is a much more thorough and detailed procedure than that described above. Far greater benefits than that discussed above may also be derived from their method, although it requires the restricting of a well's flow for considerably more time than production practices in Pennsylvania permit.

C. Estimated Losses in Ultimate Recovery

Although it is impossible to predict the ultimate gas recovery from this reservoir with any degree of accuracy, it is fairly obvious in view of the declining production rate that an uneconomical production rate will be reached long before 289 billion cubic feet of gas have been produced.

Curve DE, Figure 6, shows a recent increasing rate of decline in production rate. This may be due to a variety of factors, such as

1. Water fingering cutting off relatively high pressure gas zones.
2. Water coning near the well bore, reducing the effective sand thickness.
3. Water condensation, reducing the effective permeability to the gas.
4. Well caving
5. Structural conditions within the reservoir.
6. The temporary shutting in of an increasing number of wells (since the rate is based on the number of producing wells as drilled rather than the actual number in operation).
7. Almost total pressure depletion in densely drilled areas.

It is the author's opinion, however, that conditions in the reservoir may soon stabilize and that the flow rate after that time will continue in a directly proportional relationship with $(P_f^2-P_s^2)$; at least this is the best that can be expected. This is illustrated by the curve EF, Figure 6. Though there is little chance that this curve will hold true to the abandonment date, it is not unreasonable to expect that it will hold approximately true for the next few years. This curve may be used in conjunction with the reservoir pressure curve (Figure 4) to

provide a trial and error means for predicting future production and production rates. The dotted portions of the curves (Figure 3) were derived in this manner, considering a gradually decreasing value of P_s to zero in the year 1959. By the end of the year 1959 there should have been about 240 billion cubic feet of gas produced from this reservoir.

In consideration of curves AB and EF (Figure 6) and assuming a minimum economic flow rate (Q) of 50 MCF per day at zero back pressure (P_s), the reservoir could be expected to be abandoned at an average pressure (P_f) of 632 pounds per square inch, whereas in the "ideal" case the abandonment pressure would be 316 pounds per square inch. This, according to Figure 4, reflects a loss of about 22 billion cubic feet of gas due to inefficient production practices.

Actually, it is anyone's guess as to just how far into the future this reservoir will produce gas at an economic rate. Most likely there will be numerous wells capable of producing gas at an economic rate for many years to come. It is highly probable, however, that water fingering and coning has or will cut off relatively high pressure zones within the reservoir, and that a reduced effective permeability to gas caused by water coning and condensation will seriously curtail production and reduce the ultimate recovery. An estimated loss of approximately 20 billion cubic feet of gas is considered to be conservative.

VI. EVALUATION OF RESULTS

A. Operational Aspects

Although this study has developed no absolute proof that there will be substantial losses in ultimate recovery of gas from this reservoir, it does indicate that such losses are very likely and presents definite proof that a great amount of manpower and materials have been unnecessarily expended. Curves AB and CD (Figure 6) show that actual production per well was only about 35 per cent of what might have been expected from the properly-spaced average well, or that about one-third of the wells, if properly spaced and undamaged, should have given the same production rate. As was pointed out in Section V, A, 2, this figure is based on a conservative estimate of the slope of the logarithmic curve AB (Figure 6) equal to one. It is possible that this curve could have had a slope of less than one, showing an increasingly wide separation between the "ideal" and "actual" curves with decreasing pressures, and therefore an increasingly poorer comparison of the actual well production rate with that of the ideal.

The ideal number of wells can only be determined by an economic balance of a great many factors, such as recoverable gas in place, drilling costs, back pressure required to prevent damaging the well or the producing formation, market demands and commitments and others. The back pressure required can be determined accurately by the Bureau of Mines method, but even this is subject to economic considerations. It may, for example, be more economical to permit minor damage to the well than to hold the back pressure sufficiently high to prevent damage entirely. Some states force the application of back pressure by restricting gas

production to 25 per cent of open flow capacity. However, this restriction is also intended to prevent gas production in excess of market demands, and there is no reason known to the author why Pennsylvania should restrict production to this rate if it can be shown that significant damage will not occur to wells producing at higher capacities. All of the above factors can best be weighed and applied through a unit operation plan, assisted perhaps by a well-spacing regulation.

It is probable that no more than two billion cubic feet per month would have been the ideal production rate from the Driftwood-Benezette field. Gas companies taking gas from this field must contract for vast quantities of gas from the Southwest to meet commitments during the winter months. Furthermore, the nature of pipeline operations as well as economic factors in the producing Southwest demand the establishment of long-term contracts with little or no seasonal variations in gas deliveries. This requires the delivery of large quantities of gas to this area during the summer months which must be stored in underground reservoirs. It is therefore obvious that the most economical rate to extract gas from this field would be a long-term rate necessary to augment deliveries from the Southwest with a minimum of storing required.

According to curve AB (Figure 6), two billion cubic feet per month could have been produced early in the productive life of the field (P_f = 4600) with 27 wells producing at 25 per cent of open-flow capacity, and with 100 wells at this capacity five years later when the 120 billion cubic feet produced would have caused the reservoir pressure to drop to about 2400 pounds per square inch (Figure 4). At 50 per cent open-flow capacity, only half of these wells would be required, and 100 wells would produce two billion cubic feet or more per month until 175 billion cubic

production to 85 per cent of open flow capacity. However, this restriction is also intended to prevent gas production in excess of market demands, and there is no reason known to the author why Pennsylvania should restrict production to this rate if it can be shown that significant damage will not occur to wells producing at higher percentages. All of the above factors are best to analyze and utilize through a unit operation plan, [illegible] by a well-spacing regulation.

It is probable that no more than two billion cubic feet per month would have been the ideal production rate from the [illegible] field. The companies taking gas from this field have contracted for such quantities of gas from the [illegible] to meet peak demands during the winter months. Furthermore, the nature of pipeline operations as well as economic factors in the producing business demand the establishment of long-term contracts with little or no seasonal variations in gas deliveries. This requires the delivery of large quantities of gas to this area during the summer months which must be stored in underground reservoirs. It is therefore evident that the most economical rate to extract gas from this field would be a long-term rate necessary to support deliveries from the northwest with a minimum of storing required. [illegible]

According to curve [illegible] (Figure [illegible]), two billion cubic feet per month could have been produced early in the productive life of the field ([illegible]) with 27 wells producing at 93 per cent of open-flow capacity, and with 100 wells at this capacity five years later when [illegible] billion cubic feet produced would have caused the reservoir pressure to drop to about [illegible] pounds per square inch (Figure [illegible]). At 50 per cent open-flow capacity, only half of these wells would be required, and [illegible] wells would produce two billion cubic feet or more per month until [illegible] billion cubic

feet of gas had been produced. Assuming that the flow rate could reach a maximum at the lower pressures without causing significant damage to the wells or the formation, 100 wells would sustain the 2 billion cubic feet per month rate for almost nine years or until 210 billion cubic feet of gas had been produced. Does not this appear more efficient and logical than has been the actual practice of drilling 277 producing wells, with more to come, to obtain the flow rate shown in Figure 3?

The above comparison of actual practices with those which might have been employed under unit operations or under well spacing regulations does not show a comparison of ultimate recovery losses. It was illustrated in Section V, C that there should be at least 20 billion cubic feet of gas lost because of inefficient production practices. Though structural conditions in the reservoir might not permit such high ultimate recovery in either the actual or the ideal case, it is probable that unit operations or adequate well spacing regulations would provide for more efficient exploration and thereby for a production rate closely approaching that shown by the curve AB (Figure 6).

B. Economic Aspects

1. General

The economic aspects of production practices may be illustrated roughly as follows:

(a) Before this reservoir is abandoned there will probably have been 300 producing wells drilled -- 200 more than is conservatively estimated to be the ideal as stated in the previous section. At $75,000 per well, this will amount to an unnecessary expenditure of $15,000,000.

(b) It is estimated that at least 60 billion cubic feet of gas will have been stored and re-extracted beyond that which would have been necessary at the two billion per month rate. At an estimated cost of five cents per thousand cubic feet for storing and re-extracting, this will amount to $3,000,000.

(c) Twenty billion cubic feet of gas estimated to be lost due to open flow production practices, at an estimated net value of about ten cents per M cubic feet[22] will amount to a loss of $2,000,000.

(d) It is estimated that about 75 billion cubic feet of gas would have increased in value by at least two cents per M cubic feet had it been possible to produce this gas on a seasonal contract or at a slower rate. This will amount to $1,500,000.

(e) There have been numerous relatively minor excessive expenditures, such as expenses for operating compressor stations, additional well maintenance costs due to open flow production practices, excess gathering lines, etc.

In view of the foregoing illustration, it is reasonable to assume that $20,000,000 have or will be wasted by the production practices employed in the Driftwood-Benezette gas reservoir. Furthermore, a large

E. Economic Aspects

1. General

The economic aspects of production practices may be illustrated roughly as follows:

(a) Before this reservoir is abandoned there will probably have been 300 producing wells drilled -- 200 more than is conservatively estimated to be the ideal as stated in the previous section. At $75,000 per well, this will amount to an unnecessary expenditure of $15,000,000.

(b) It is estimated that at least 60 billion cubic feet of gas will have been stored and re-extracted beyond that which would have been necessary at the two billion per month rate. At an estimated cost of five cents per thousand cubic feet for storing and re-extracting, this will amount to $3,000,000.

(c) Twenty billion cubic feet of gas estimated to be lost due to open flow production practices, at an estimated net value of about ten cents per M cubic feet[22] will amount to a loss of $2,000,000.

(d) It is estimated that about 75 billion cubic feet of gas would have increased in value by at least two cents per M cubic feet had it been possible to produce this gas on a seasonal contract or at a slower rate. This will amount to $1,500,000.

(e) There have been numerous relatively minor excessive expenditures, such as expenses for operating compressor stations, additional well maintenance costs due to open flow production practices, excess gathering lines, etc.

In view of the foregoing illustration, it is reasonable to assume that $20,000,000 have or will be wasted by the production practices employed in the Driftwood-Benezette gas reservoir. Furthermore, a large

portion of these losses will be paid by the consumer in the form of high gas prices or in taxes to make up for the losses from state-owned tracts.

2. Private Landowners

Much of the land overlying this reservoir is privately owned small tracts of one acre or less. Such a landowner's fair share of the gas, considering 40,000 acres total and 280 billion cubic feet of gas as recoverable, is 7,000 M cubic feet. At one-eighth royalty this figure is further reduced to roughly 900 M cubic feet, which would amount to $247.50 at the current price of 27½ cents per M cubic feet. It is conservatively estimated that many small tract landowners have or will receive at least a hundred times this figure. Their excess profits obviously resulted in losses from less densely drilled areas, which in this field are mostly state-owned tracts.

VII. CONCLUSIONS AND RECOMMENDATIONS

It is concluded that there have been about 200 excess wells drilled in the Driftwood-Benezette field; that there could not possibly have been a fair and equitable distribution of the gas among the various landowners; that very probably there have or will be large quantities of gas left in the reservoir because of open-flow production practices; that sound engineering principles are not observed in gaging wells and in evaluating their performance, and that all of these are directly attributable to the lack of petroleum regulatory statutes in Pennsylvania. It is further concluded that the general public supports a large share of the inequities, gas losses and excess expenses either in higher gas prices or in decreased revenue from publicly owned land.

The obvious recommendation, therefore, is that the citizens of Pennsylvania demand the enactment of state statutes which will prevent this waste of manpower, materials, and petroleum resources, and which will insure the protection of correlative rights of landowners.

The details of the varied petroleum conservation measures and unitization statutes are beyond the scope of this paper. The average citizen, however, should not be so much concerned with these details as by the fact that nothing is being done to remedy the current inefficient and unfair production practices. Citizens should place their faith in an Oil and Gas Commission appointed for the purpose of recommending appropriate conservation and unitization statutes and for enforcing the statutes after they are enacted. No person need fear monopolistic practices or the deprivation of his property without due due process of law. He is protected from these under federal law.

It is additionally recommended that the State immediately institute a program to acquire, compile and correlate information needed for accurate engineering studies, and to make this information readily available to all interested parties. No information relating to well production should be confidential. The very least that should be done is the enactment of a law requiring that all gas wells be shut in for a minimum of 48 hours once a year and that shut-in pressures be recorded and reported to an appropriate state regulatory body. Open-flow capacities, or flow rates against stated back pressures, should be recorded at the time wells are shut in, and likewise reported. Though this information will not suffice for accurate computation of the wells' performance by the Bureau of Mines back-pressure method, it will provide for considerably more accurate engineering studies than are currently possible. This recommendation would be superfluous if adequate petroleum conservation laws were enacted, for effective conservation presupposes a requirement for accurate knowledge of both the gas reservoir and the producing wells, which can only be gained from extensive and accurate data.

A P P E N D I C E S

APPENDIX I

Producing Wells in the Driftwood-Benezette Gas Field

Well No. and Area*	Name and Number	Drilling Completed	Depth	Flow Mcf/day	Initial W.H.P. psig
1-A	S.C. Eaton, Jr. #1(Sylv.)	9-15-51	5922	4,000	3925
11-N	Bearpaw Rod & Gun #1 (Fralich)	5-5-52	5876	4,900	3950
23-O	B & O #1 (Plymouth)	6-23-52	5952	80	-
25-A	Caldwell #1	7-9-52	5836	1,000	3500
29-A	Mix Run School Lot #1	7-25-52	5830	3,300	3950
36-N	J. W. Moate #1	8-18-52	6143	6,880	850
37-A	B. R. & G. #1 (Fox)	8-29-52	5802	3,200	2850
38-A	Caldwell #1	9-10-52	5846	700	-
41-A	Caldwell #2	10-3-52	5857	3,400	2700
43-O	McMillian Est. #1(Delta)	10-10-52	5820	6,100	3400
45-O	S. C. Eaton #6	10-13-52	5996	3,500	3340
47-A	St. 2 Tr. 19	10-27-52	7051	1,000	3650
50-A	Moate #1 (Fox)	11-14-52	5862	1,200	3050
52-O	S. C. Eaton, Jr. #4	11-26-52	5903	838	2700
53-A	S. C. Eaton, Jr. #2(Sylv)	12-8-52	6227	1,620	2500
54-N	St. 1 Tr. 20	12-8-52	5927	4,500	3655
55-O	S. C. Eaton, Jr. #2(NYSN)	12-9-52	5944	2,100	2250
57-S	Charleroi Mt. Club #1	12-30-52	6975	2,800	3810
58-N	St. 2 Tr. 20	12-31-52	6408	1,900	3200
59-A	S. Moate #1 (Pamco)	1-2-53	5840	2,560	1775
60-A	S. Moate #2	1-2-53	5851	2,166	2925
61-O	Eaton #7	1-3-53	5822	2,274	2170
62-A	Brookbank #1	1-5-53	5887	3,100	3250
63-N	H. A. Moate #1(Sylvania)	1-10-53	6072	177	660
64-B	H. L. Pearsall #1	2-2-53	5975	3,000	3400
65-A	H. A. Moate #2	2-18-53	5984	134	1520
66-N	Clyde L. Smith #1	2-20-53	6075	239	-
67-O	S. C. Eaton #5	2-20-53	5980	2,386	1805
69-F	Wm. Waldring #1	3-9-53	6153	713	800
72-F	W. A. Thurby #1	3-24-53	6101	8,000	4000
74-Q	Sagamore Hunt Club #1	4-1-53	6893	18,200	2150
75-S	Catherine Bartolette #1	4-11-53	6134	9,500	3950
77-N	Eaton #8	4-21-53	6390	3,450	1740
79-S	Charleroi Mt. Club #3	5-2-53	6936	17,000	-
80-N	Clyde Smith #2	5-14-53	6150	1,017	1310
81-N	Eaton #9	5-15-53	6810	2,600	1745
82-B	B & O #2	5-27-53	5870	1,200	1900
84-S	Charleroi Mt. Club #2	6-1-53	6943	5,250	3300
85-R	Sagamore Hunt Club #1	6-2-53	6903	8,900	3675
86-S	Johnson Est. #1	6-3-53	6307	9,800	4020
88-B	St. 4 Tr. 19	6-10-53	6019	300	-
89-N	Moate #3	6-12-53	6592	1,038	1400
92-O	Charles Buell #1	6-20-53	6168	400	2860

*Wells shown by number and area in Figure 2. Missing numbers in the sequence indicate dry holes drilled in or near the field.

APPENDIX I (Continued)

Well No. and Area*	Name and Number	Drilling Completed	Depth	Flow Mcf/day	Initial W.H.P. psig
93-N	H. A. Moate #5	6-22-53	6040	1,473	-
94-N	H. A. Moate #4	6-22-53	6190	2,100	2575
96-F	Bateman #1	6-27-53	6112	16,980	3830
97-F	B & O RR #1(Mid-Atlantic)	7-11-53	6087	12,250	3600
98-A	B & O #1 (Chs. Sample)	7-14-53	5880	4,500	2300
99-O	McMillian #1 (Kane)	7-22-53	5994	1,100	880
101-F	Theo. Stem #1	7-22-53	6085	8,500	3720
102-F	O. Johnson #1	7-23-53	6202	9,250	3750
103-K	Pearsall #1 (Fralich)	7-28-53	6974	25,500	3700
104-H	Van Voorhees #1 (Simon)	7-29-53	6099	9,600	3880
105-F	J. Miller #1	8-1-53	6048	7,000	3745
106-B	Charleroi #6	8-7-53	6218	2,700	3720
107-S	St. 4 Tr. 29	8-10-53	6870	2,075	3550
108-F	B. Johnson #1	8-11-53	6196	5,000	3020
109-F	P.R.R. #1	8-11-53	-	4,200	-
110-F	B. Johnson #2	8-11-53	6119	4,000	3170
111-F	J. Miller #2	8-14-53	6122	5,200	3000
112-F	Grafton (Camp Shanty) #1	8-14-53	6146	5,750	3000
113-A	H. A. Moate #6	8-14-53	6023	3,000	2250
114-G	R. Weiss #1	8-16-53	6141	5,000	2500
115-H	Pontzer #1	8-18-53	6116	13,700	3000
116-F	Sam Ena #1	8-18-53	6110	9,600	3700
117-B	Brookbank #2	8-20-53	5896	2,600	2300
118-G	Bartolette #2	8-20-53	6269	10,500	-
119-F	Overturf #1	8-21-53	-	9,000	-
120-B	A. J. Moser #1	8-21-53	5995	2,300	3100
121-D	Vause #1	8-22-53	6109	3,125	3925
122-F	Nicolo Pascuzzi #1	8-24-53	6160	1,800	3200
123-F	Thunderbird Camp #1	8-25-53	6137	5,700	2860
124-H	Johnson Est. #3	8-25-53	6263	16,000	3200
125-H	Mackey #1	8-28-53	6105	14,500	—
126-I	Stiveson #1	8-31-53	6163	5,731	3000
127-I	W. A. Thurby #2	9-1-53	6276	5,300	2725
128-F	J. H. Roger #1	9-1-53	6272	5,700	2750
129-H	Gombel #1	9-3-53	6121	34,000	3360
130-I	Steffy #1	9-4-53	6215	7,000	3000
132-S	St. 2 Tr. 29	9-9-53	6947	4,332	3220
133-E	Johns #1	9-10-53	6073	8,530	3050
134-A	P.E.R. #2	9-10-53	5860	1,800	1000
135-SS	St. 1 Tr. 33	9-18-53	6392	7,350	3920
136-Q	Sagamore Hunt #4	9-22-53	6890	2,067	-
137-G	Overturf #2	9-25-53	6088	14,700	2500
138-H	H. Bleish #1	9-26-53	7011	7,300	-
139-G	Rothrock #2	9-28-53	6108	12,300	2590
140-G	B & O #2 (Mid-Atlantic)	9-28-53	6131	3,000	-
141-F	Coleman #1	9-29-53	6147	5,300	1960
142-H	Rothrock #3	9-30-53	6128	8,600	-

APPENDIX I (Continued)

Well No. and Area*	Name and Number	Drilling Completed	Depth	Flow Mcf/day	Initial W.H.P. psig
143-T	Charleroi Mt. Club #5	9-30-53	6305	8,000	2800
144-H	Johnson Est. #2 (Kets)	10-1-53	6497	6,800	2600
145-F	Hot Shot Camp #1	10-3-53	6160	3,470	1980
146-H	Van Voorhees #1 (Kahle)	10-3-53	6114	11,000	2575
147-F	Mountain Camp #1	10-6-53	6190	3,750	1900
151-T	Ahlborn Coal Co. #1	10-12-53	6960	28,000	-
152-I	Thurby #4	10-13-53	6394	7,960	2800
154-G	Charleroi #10	10-14-53	6118	16,000	2550
155-E	Pasley Ober #1	10-17-53	6064	4,750	3600
156-AA	St. 2 Tr. 28	10-20-53	6999	6,000	3260
157-MM	St. 1 Tr. 32	10-21-53	7034	1,313	3140
158-L	St. 6 Tr. 20	10-21-53	-	3,400	3500
159-Z	St. 5 Tr. 29	10-24-53	6914	14,850	3290
160-A	Pearsall #1 (Sylvania)	10-26-53	6975	6,000	3375
161-H	Rothrock #1	10-25-53	6099	7,000	-
162-P	St. 2 Tr. 27	10-30-53	6935	10,849	3440
163-D	N. Kindroburiak #1	10-31-53	6092	1,438	-
164-I	St. 1 Tr. 34 A	11-2-53	6975	8,500	3625
165-FF	St. 9 Tr. 29	11-2-53	6900	14,671	3620
166-AA	St. 2 Tr. 30	11-2-53	6977	5,000	3460
167-G	Rothrock #5	11-2-53	6112	8,000	1850
168-F	Green #1	11-3-53	6154	3,300	1600
169-H	Charleroi R & G #7	11-4-53	6102	26,000	3250
171-F	Sam Anz #1 (Shearer)	11-5-53	6310	5,900	-
172-E	Billings-Mason #2	11-10-53	6062	4,800	-
173-Q	St. 1 Tr. 27	11-11-53	6936	10,500	3210
175-Q	Sagamore Hunt Cl. #3	11-13-53	6128	22,500	3065
176-F	Cora Bennett #1	11-17-53	6185	1,474	1600
177-R	St. 1 Tr. 28	11-20-53	6938	20,100	3210
178-H	Rothrock #4	11-22-53	6119	11,250	-
179-R	St. 3 Tr. 29	11-25-53	6965	4,642	3210
180-H	S & R #4 (Mid-Atlantic)	11-25-53	6069	4,900	1500
181-AA	St. 1 Tr. 30	11-25-53	6566	412	3000
182-J	St. 1 Tr. 26	11-25-53	6903	4,073	3225
183-F	Belts #1	11-26-53	6157	4,200	1500
184-F	Mowry #1	11-26-53	6842	7,000	-
185-F	Lawrence Winslow #1	11-28-53	6891	3,373	2600
186-H	Pontner #2	12-3-53	6175	8,200	1450
187-X	Denver Miller #1	12-3-53	6885	8,200	3750
188-I	Allegheny Camp #1	12-3-53	6169	3,000	1450
189-J	Ahlborn Coal #1	12-3-53	6999	8,400	3150
190-F	Overturf #3	12-4-53	6240	1,100	-
191-R	Sagamore Hunt Cl. #2	12-4-53	-	6,500	3100
192-I	Thurby #5	12-4-53	6175	8,000	2100
193-H	Charleroi #9	12-5-53	6187	10,750	-
194-F	B & O RR #5	12-5-53	6062	4,200	2400
195-F	Lewis Jourdain #1	12-7-53	6199	1,350	1500
197-F	Arthur Davis #1	12-9-53	6212	2,700	1450

APPENDIX I (Continued)

Well No. and Area*	Name and Number	Drilled Completed	Depth	Flow Mcf/day	Initial W.H.P. psig
198-T	St. 6 Tr. 29	12-10-53	6965	17,196	3100
199-F	Davis & Snyder #1	12-11-53	6136	2,560	1450
200-G	Ahlborn Coal #2	12-14-53	6390	2,300	2900
201-Q	St. 3 Tr. 27	12-23-53	7015	4,333	2350
202-AA	St. 3 Tr. 28	12-26-53	6964	1,100	3150
203-H	Jumble #2	12-27-53	6172	10,000	1250
205-F	Camp Kidd #1	1-2-54	6137	2,646	1340
206-W	Wm. Laughlin #1	1-2-54	6258	3,125	3750
207-E	Sam Ens #2 (Mid-Atlantic)	1-2-54	6103	7,810	3100
208-E	Cooks Camp #1	1-4-54	6146	4,275	3600
209-AA	St. 8 Trl 29	1-5-54	6940	342	3380
210-I	Stiveson #1	1-6-54	6380	7,500	2590
211-T	Charleroi B & O #4	1-6-54	6380	7,500	2590
212-EE	St. 1 Tr. 31	1-8-54	7081	140	-
214-D	Schiller #1	1-13-54	6102	3,000	-
215-F	St. 1 Tr. 34	1-15-54	6383	2,588	1900
217-C	H. & J. Mason #2	1-15-54	6140	6,000	3750
216-F	King Gold Club #1	1-15-54	6116	2,000	1400
218-T	St. 7 Tr. 29	1-26-54	6893	9,811	-
219-P	Pearsall #2 (Sylvania)	1-26-54	6223	24,300	2723
220-T	Ahlborn Coal #2	1-26-54	6935	4,500	2150
221-F	Wm. Woodring #1 (Haddox)	1-27-54	6224	6,000	1600
222-F	Camp Linda #1	1-30-54	6183	1,650	1050
223-H	Charleroi #3	2-1-54	6204	7,300	-
225-BB	St. 5 Tr. 31	2-4-54	7007	4,875	3500
227-H	B & O #6	2-5-54	6118	6,100	-
228-B	B & O #2 (Chs. Sample)	2-10-54	6973	600	1800
229-E	Sam Ens #3	2-11-54	6224	1,438	3150
230-T	St. 12 Tr. 29	2-11-54	6940	3,523	2300
231-G	Ahlborn Coal #2	2-11-54	6905	7,000	2125
232-AA	St. 1 Tr. 29	2-12-54	6905	4,760	2510
233-H	Thurby #6	2-13-54	6923	4,100	1450
234-X	Dollinger #1	2-13-54	6442	1,178	3580
236-W	Heffelfinger #1	2-15-54	6254	557	-
239-G	Wm. Shuck #1	2-19-54	6052	1,438	3000
240-N	Shingledecker #1	2-20-54	6259	1,300	3750
241-OO	St. 1 Tr. 36	3-1-54	7155	12,800	3830
243-W	St. 6 Tr. 31	3-4-54	6444	40,234	3560
245-D	Dents Run Coal #1	3-10-54	6092	400	2340
246-P	St. 5 Tr. 27	3-12-54	6159	82	1650
247-F	B & O #1 (J.I. Shearer)	3-13-54	6132	557	950
248-G	Ahlborn Coal #3	3-16-54	6993	5,538	1850
249-R	St. 4 Tr. 28	3-16-54	6998	4,770	2050
252-EE	St. 1 Tr. 34B	3-22-54	7295	125	-
254-W	St. 1 Tr. 38	3-25-54	6226	5,454	3850
255-L	St. 2 Tr. 25	3-30-54	6995	4,860	2600
256-P	St. 4 Tr.27	3-30-54	7122	13,000	1850
257-CC	St. 5 Tr. 28	3-31-54	6911	6,000	1850

APPENDIX I (Continued)

Well No. and Area	Name and Number	Drilling Completed	Depth	Flow Mcf/day	Initial W.H.P. psig
258-MM	St. 4 Tr. 33	4-3-54	6201	4,854	3500
259-I	Thurby #7	4-3-54	6918	21,000	1450
260-Y	St. 5 Tr. 34A	4-10-54	6394	8,500	2825
261-U	Bleish #3	4-12-54	6941	968	1550
262-T	Ahlborn Coal #4	4-12-54	6868	4,000	-
263-N	Amy Laughlin #1	4-13-54	6254	852	2700
268-X	St. 3 Tr. 31	4-16-54	6381	7,810	3260
269-R	St. 8 Tr. 26	4-18-54	6741	2,427	2000
270-Q	Sagamore #5	4-18-54	6475	6,400	1775
272-II	St. 2 Tr. 38	4-22-54	6625	6,000	3625
274-T	Ahlborn Coal #5	4-27-54	6938	4,000	1575
275-Y	St. 1 Tr. 34B	4-28-54	7151	1,000	3550
276-Z	St. 2 Tr. 34A	4-28-54	7000	308	1950
277-OO	St. 3 Tr. 32	4-29-54	7176	5,523	2980
280-M	Bleish #4	5-1-54	7001	8,500	1425
281-X	Parke #1 (Kahle et al)	5-3-54	6428	3,250	2875
282-E	Billings and Maxon #1	5-3-54	6119	4,600	2160
284-F	Bateman #1	5-5-54	6146	696	700
285-Q	St. 7 Tr. 25	5-7-54	6060	2,350	2150
286-X	Danielson #1	5-8-54	6254	475	3000
287-W	St. 1 Tr. 25	5-12-54	6992	7,035	2450
288-MM	St. 2 Tr. 33	5-17-54	7019	4,151	3160
289-M	Logue #1	5-17-54	6247	1,400	2500
290-U	St. 13 Tr. 29	5-19-54	6892	4,900	2800
291-BB	St. 5 Tr. 30	5-20-54	7024	5,731	2560
292-X	Parks #1 (Layton)	5-20-54	6393	2,438	2500
294-J	St. 6 Tr. 26	5-21-54	6929	3,021	2450
295-T	Charleroi #12	5-27-54	7039	4,400	1850
296-X	St. 10 Tr, 29	5-27-54	6944	550	2500
297-X	St. 4 Tr. 34A	5-29-54	7112	250	1650
298-DD	St. 6 Tr. 6	6-1-54	7080	3,479	2940
299-MM	St. 5 Tr. 33	6-1-54	6313	14,210	2916
301-J	St. 2 Tr. 26	6-5-54	6934	2,085	2175
302-Z	St. 3 Tr. 34A	6-7-54	7029	4,272	2650
304-K	St. 9 Tr. 26	6-9-54	6959	4,973	2050
305-OO	St. 1 Tr. 34C	6-10-54	7106	1,217	2625
306-U	St. 14 Tr. 29	6-10-54	6809	38,000	3125
307-WW	St. 2 Tr. 32	6-10-54	7111	1,174	1790
308-KK	St. 3 Tr. 38	6-11-54	6220	38,000	3125
309-F	Holben #1	6-12-54	6147	600	-
310-DD	St. 2 Tr. 34C	6-19-54	7102	12,572	3300
311-K	R. L. Pearsall #4	6-21-54	6331	2,200	1820
312-HH	St. 2 Tr. 37	6-21-54	6224	4,450	2980
313-I	Thurby #3	6-22-54	6939	1,500	-
315-X	Parks #1 (Bailey)	6-26-54	6366	1,600	2040
316-Q	Sagamore #7	6-28-54	6491	2,800	1425
319-D	St. 11 Tr. 26	7-2-54	6208	189	2100
320-I	Thurby #8	7-7-54	7046	700	1300

APPENDIX I (Continued)

Well No. and Area	Name and Number	Drilled Completed	Depth	Flow Mcf/day	Initial W.H.P. psig
322-I	St. 12 Tr. 26	7-13-54	6918	2,218	2050
323-LL	St. 6 Tr. 33	7-16-54	6366	1,857	1620
324-KK	St. 4 Tr. 38	7-20-54	6287	213	2275
325-X	St. 16 Tr. 29	7-24-54	6373	920	2450
326-F	Pascuzzi #1	7-24-54	6063	2,463	1300
327-OO	St. 4 Tr. 36	7-29-54	7095	990	1850
328-BB	St. 4 Tr. 30	7-29-54	6920	2,936	-
329-T	St. 17 Tr. 29	7-30-54	7004	42,000	1910
332-E	St. 10 Tr. 26	8-2-54	6866	1,279	2350
334-FF	St. 11 Tr. 31	8-13-54	7102	1,000	2500
335-X	Herman Morre #1	8-14-54	6232	4,500	3700
337-KK	St. 1 Tr. 29	8-24-54	6473	6,100	3050
339-V	Denver Miller #3	9-3-54	6750	2,800	3150
340-X	Roosensteel #1	9-4-54	6232	3,300	3100
341-LL	St. 8 Tr. 33	9-14-54	6303	5,741	1340
342-HH	St. 3 Tr. 33	9-15-54	7007	996	1990
343-R	Sagamore #6	9-16-54	6417	2,542	1280
344-W	St. 7 Tr. 31	9-18-54	6315	1,081	1580
346-V	Dollinger #1	10-8-54	6262	5,080	2650
349-LL	St. 9 Tr. 33	10-11-54	6420	239	1410
350-B	St. 7 Tr. 20	10-11-54	6907	1,271	1450
351-Y	St. 11 Tr. 29	10-12-54	6950	3,373	1650
353-B	Billings and Mason #3	10-21-54	6830	2,250	1530
354-V	Steve Rupprecht #1	10-27-54	6902	4,200	2290
356-L	Pearsall #5	10-29-54	7021	1,835	1425
357-W	Paul Chase #1	11-6-54	6341	10,833	3600
358-V	Dollinger #2	11-9-54	6760	3,769	2310
359-W	Crufutt (Ross Hrs.) #1	11-13-54	6204	2,166	3175
362-C	H. & J. Mason #1	11-29-54	6932	134	-
363-KK	St. 2 Tr. 29	11-31-54	7145	1,246	-
364-QQ	St. 2 Tr. 34	12-3-54	7113	680	1400
365-X	Claude Chase #1 (Kahle)	12-10-54	6239	3,921	1507
366-V	Walter Turle #1	12-13-54	6216	4,047	1700
368-W	St. 3 Tr. 37	12-20-54	6884	3,425	3500
370-X	Boosters Club #1	1-17-55	6182	5,500	2500
371-X	Crown Control #1	1-17-55	6220	1,600	2160
372-W	St. 4 Tr. 37	1-19-55	7029	5,731	2725
373-JJ	St. 11 Tr. 33	2-22-55	6283	4,275	-
374-II	St. 5 Tr. 38	2-23-55	6943	2,900	1800
375-II	St. 5 Tr. 37	2-25-55	7076	894	2850
376-W	Hall Chase #2	2-26-55	6598	3,000	2400
377-Z	St. 18 Tr. 29	3-3-55	7029	4,775	1120
378-DD	St. 7 Tr. 30	3-10-55	7225	696	1140
379-J	St. 20 Tr. 29	3-16-55	6508	4,055	1125

APPENDIX II - CALCULATIONS*

A. Determination of Reserves

1. P/Z Values for Graphical Solution (Figure 4)

Gas Analysis: methane 97.0%; ethane 2.10%; propane 0.1%; oxygen 0.1%; nitrogen 0.5; carbon dioxide 0.2%; molecular weight 16.3; critical pressure 673 psia; critical temperature 348°R.

Reservoir temperature 150°F**; surface temperature 60°F. Original reservoir pressure P = 4035 psia as measured at the surface plus the pressure caused by the weight of the gas column in the well P_x. P_x was calculated as follows:

$$P_w = \frac{144\ ZRT\ P_x}{MH} - .5\ P_x$$

where P_w = 4035 psia well head pressure

Z = .9 (from compressibility chart for natural gas, using a pseudo reduced pressure P_r of 4035 ÷ 673 = 6.0, and a pseudo reduced temperature T_r of 565° R ÷ 348 = 1.622)

R = 10.71 (gas constant)

T = 565°R (average temperature in the well)

H = 6500 feet (average depth)

M = 16.3 (molecular weight)

thus

$$4035 = \frac{(144)(.9)(10.71)(565)\ P_x}{(16.3)(6500)} - .5\ P_x$$

P_x = 583 pounds per square inch.

*All calculations by slide rule

**Estimate based on 140°F. as measured for Leidy gas field

Therefore, the original reservoir pressure $P = 4035 + 583 = 4618$ pounds per square inch absolute. The corresponding compressibility factor $Z = .97$, using $T_r = 610^\circ R$ (reservoir temperature) $\div 348 = 1.75$, and $P_r = 4618 \div 673 = 6.85$. The original $P/Z = 4618 \div .97 = 4755$.

On May 31, 1954, P_x and Z were calculated as shown above. (See Figures 7 and 8)

May 31, 1954 $P/Z = \dfrac{P_w + P_x}{Z} \quad \dfrac{2505 + 390}{.882} = 3280$

2. Analytical Method

Original gas = gas produced + gas remaining

Considering the reservoir storage space and the reservoir temperature as remaining constant, and using the gas produced as of May 31, 1954 (Appendix III):

$$\frac{381\ P_1 V}{Z_1\ RT} = 89{,}315{,}450{,}000 + \frac{381\ P_2 V}{Z_2\ RT}$$

where 381 = standard cubic feet per mole

$P_1 = 4618$ psia (original reservoir pressure)

$P_2 = 2895$ psia (May 31, 1954 reservoir pressure)

V = reservoir storage space in cubic feet

$Z_1 = .97$ (compressibility factor at original reservoir pressure)

$Z_2 = .882$ (compressibility factor at May 31, 1954 reservoir pressure)

$R = 10.71$ (gas constant)

$T = 610^\circ R$ (reservoir temperature)

$$V = \frac{89{,}315{,}450{,}000\ RT}{381(P_1/Z_1 - P_2/Z_2)}$$

$$V = \frac{(89{,}315{,}450{,}000)(10.71)(610)}{381\ (4755 - 3280)} = 1.04 \times 10^9 \text{ cubic feet}$$

$$\text{Original gas} = \frac{381\ P_1 V}{Z_1\ RT} = \frac{(381)(4618)(1.04 \times 10^9)}{(.97)(10.71)(610)}$$

$$= 289 \text{ billion standard cubic feet}$$

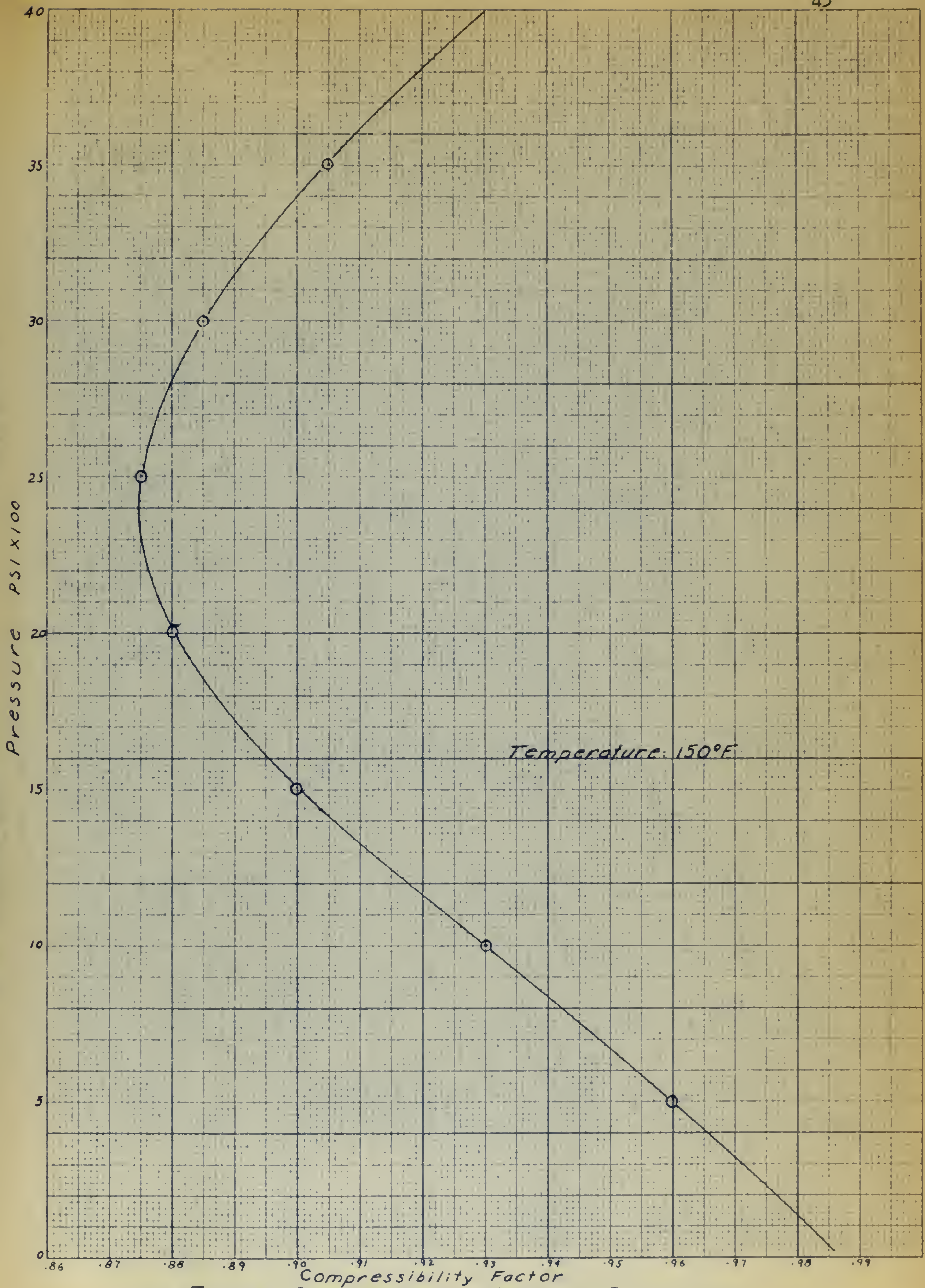


Figure 7. Compressibility Factor vs. Pressure

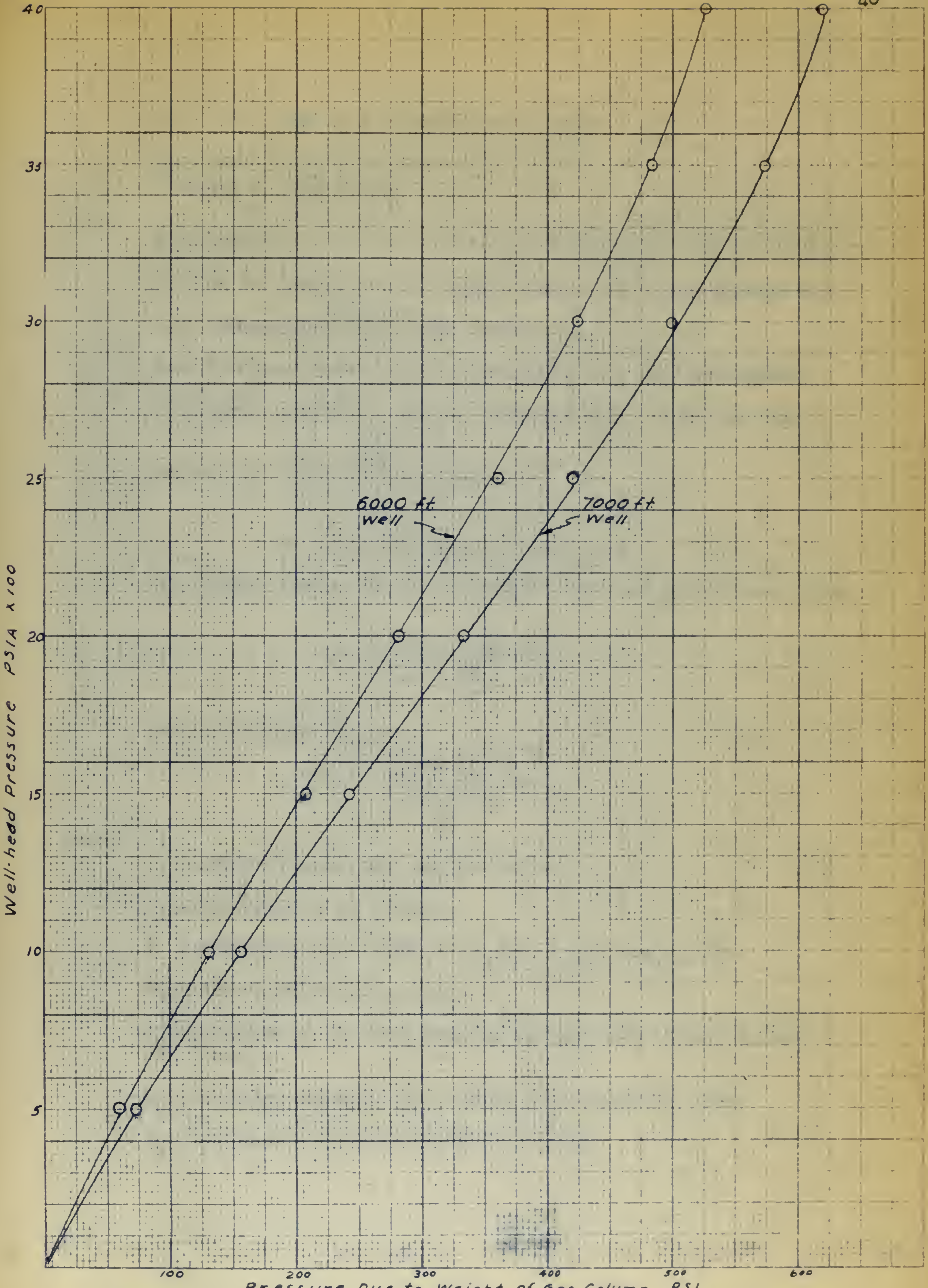


Figure 8. Pressure Due to Weight of Gas Column vs Well-head Pressure

B. Determination of Porosity

$$\text{Porosity} = \frac{\text{pore volume}}{\text{bulk volume}}$$

Pore volume = 1.04×10^9 cu. ft. (as shown in Appendix II, Section A, 2 on the preceding page) plus an estimated 20 per cent of the pore volume for connate water saturation.

Bulk volume = approximately 42,000 acres x 17 feet averagesand thickness x 43,560 cu. ft. per acre-foot = 31.1×10^9 cu. ft.

$$\text{Porosity} = \frac{(1.04 \times 10^9)(100)}{(31.1 \times 10^9)(1-.20)} = 4.18\%$$

C. Determination of Permeability

The Darcy's Law radial flow equation[23] for viscous isothermal flow

$$Q_b = \frac{19.88\ Kh\ (P_e^2 - P_w^2)}{P_b\ \mu\ \ln \frac{r_e}{r_w}}$$

can be rewritten to give

$$Q_s = \frac{703\ Kh\ (P_f^2 - P_s^2)}{\mu\ \ln \frac{r_e}{r_w}\ T_f}$$

where

Q_s = standard cubic feet per 24 hours

K = permeability in darcies

h = effective sand thickness in feet (approximately 17)

P_f = reservoir pressure, psia

P_s = pressure at the sand face (or flowing bottom hole pressure) psia

r_e = drainage radius of the well in feet (estimated 1000)

r_w = radius of the well bore in feet (.256)

μ = viscosity in centipoises (about .021)

T_f = flowing temperature, °R (610)

In the equation $Q = C(P_f^2 - P_s^2)^n$, when n equals one, C is equivalent to:

$$\frac{703\ Kh}{\mu\ \ln r_e/r_w\ \ T_f}$$

Therefore,

$$K = \frac{C\ \mu\ \ln r_e/r_w\ \ T_f}{703\ h}$$

substituting:

$$K = \frac{(.4561)(.021)(8.27)(610)}{(703)(17)}$$

K = .00405 darcy or 4.05 millidarcies

APPENDIX III

Monthly and Cumulative Production
(Thousands of Standard Cubic Feet)

Date	Monthly	Cumulative
July, 1952	188,059	188,059
August	335,508	523,567
September	487,600	1,011,167
October	626,391	1,634,558
November	646,559	2,284,117
December	779,402	3,063,519
January, 1953	707,450	3,770,969
February	675,666	4,446,635
March	702,671	5,149,306
April	699,867	5,849,173
May	914,232	6,763,405
June	2,064,370	8,827,775
July	3,325,838	12,153,613
August	3,813,343	15,966,956
September	4,631,769	20,598,725
October	5,921,232	26,519,557
November	8,547,966	35,067,923
December	9,417,934	44,085,857
January, 1954	9,566,001	54,051,858
February	8,455,139	62,523,997
March	8,814,765	71,338,762
April	9,079,005	80,417,767
May	8,897,687	89,315,454
June	8,632,640	97,948,094
July	9,035,862	106,983,956
August	8,402,474	115,386,430
September	7,224,472	122,610,902
October	6,493,945	129,104,847
November	6,122,523	135,227,370
December	5,605,069	140,832,439
January, 1955	5,392,746	146,225,185
February	4,238,335	150,463,520
March	4,306,508	154,770,028
April	3,835,448	158,605,476
May	3,591,968	162,197,444

APPENDIX IV

Producing Wells and Dry Holes by Dates

Date	Total No. Prod. Wells	Total No. Dry Holes	Date	Total No. Prod. Wells	Total No. Dry Holes
Sept., 1951	1	-	July, 1953	53	52
October	1	-	August	75	52
November	1	-	September	91	53
December	1	1	October	107	57
January, 1952	1	1	November	127	59
February	1	4	December	144	61
March	1	7	January, 1954	161	62
April	1	9	February	175	67
May	2	15	March	187	72
June	3	22	April	201	80
July	5	28	May	217	82
August	7	31	June	233	86
September	8	33	July	243	88
October	12	37	August	247	93
November	14	39	September	253	94
December	19	40	October	260	98
January, 1953	24	40	November	265	100
February	28	40	December	269	101
March	30	44	January, 1955	272	102
April	33	45	February	276	102
May	37	47	March	277	102
June	46	51	April	277	102
			May	277	102

BIBLIOGRAPHY

1. Eckert, F. C., "Why We Should Have Regulated Well Spacing," Producers Monthly, November, 1954, p. 33.

2. Wing, Robert C., "Pennsylvania Law," Prospective Unit Operation of Oil and Gas Reservoirs in Pennsylvania, (Master of Science thesis, University of Pittsburgh), 1952, pp. 11-13.

3. "A Form for an Oil and Gas Conservation Statute," A Drafting Subcommittee of the Legal Committee, the Interstate Oil Compact Commission as amended May 5, 1950.

4. Rawlins, E. L., and Schellhardt, M. A., "Back-Pressure Data on Natural-Gas Wells and Their Application to Production Practices," U. S. Bureau of Mines Monograph 7, (1935).

5. Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 8.

6. Bolger, Robert C., and Gouse, Harry V., "Surface and Subsurface Structure of the Driftwood Quadrangle Pennsylvania," Pennsylvania Topographic and Geologic Survey Bulletin M 36, 1953, p. 23.

7. Fettke, C. R., "Structure Contour Maps of the Plateau Region of North-central and Western Pennsylvania," Pennsylvania Topographic and Geologic Survey Bulletin G-27 (1954), Plate 3, Northeast Sheet.

8. Bolger, Robert C., "Geologic Structure of Parts of the Chestnut Ridge and Driftwood Anticlines," Pennsylvania Geologic Survey Progress Report 142, 1953.

9. Wagner, H. J., "Lost Circulation and Completion Problems Eased," World Oil, January, 1955, p. 116.

10. Cornell, David, "How You Can Compute Gas Reserves More Accurately," World Oil, December, 1952, p. 220.

11. Calhoun, John C., "Example of Reserve Estimates by Gas Law," Fundamentals of Reservoir Engineering, University of Oklahoma Press, 1953, pp. 206-208.

12. Fettke, Charles R., "Physical Characteristics of the Oriskany Sandstone," Pennsylvania Topographic and Geologic Survey Bulletin 102B, December, 1931, p. 2.

13. Ebright, John R., and Ingham, Albert I., "Geology of the Leidy Gas Field and Adjacent Areas," Pennsylvania Topographic and Geologic Survey Bulletin M34, 1951, p. 19.

14. Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 8.

15. Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 79.

BIBLIOGRAPHY (Continued)

16. Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 2.

17. Schellhardt, M. A., "Application of the Back-Pressure Method for Determining Absolute Open Flows of Large Gas Wells," Bureau of Mines Report of Investigation 3767, August, 1944, p. 4.

18. Muskat, M., and Botset, H. G., "Flow of Gas Through Porous Materials," Physics, American Physical Society, vol. 1, July, 1931, p. 40.

19. Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 9.

20. Rawlins, E. L., and Schellhardt, M. A., op. cit., p. 103.

21. Ebright, John R., and Ingham, Albert I., loc. cit.

22. Eckert, F. C., op. cit., p. 34.

23. "Recommended Practice for Determining Permeability of Porous Media," American Petroleum Institute, API RP 27, 1952, p. 23.

Thesis
C7036 Connally 28995
An engineering study of the driftwood-benezette gas field in Pennsylvania.